DATA REQUEST

KPSC PHDR_1	Refer to Direct Testimony of Tanner S. Wolfram (Wolfram Direct Testimony), page 22, line 5 through line 6. Provide a copy of any minutes from the May 28, 2025 meeting of the Mitchell Operating Committee.

RESPONSE

Please see KPCO_R_KPSC_PHDR_1_Attachment1.

Witness: Tanner S. Wolffram

MITCHELL OPERATING COMMITTEE

AGENDA

May 28, 2025

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") will be held on May 28, 2025, at 1:00 p.m. (Eastern).

Invitees: Operating Representatives: Cynthia Wiseman (Kentucky Power), Aaron Walker (Wheeling Power), Alex Vaughan (Agent)

Other Invitees: John Crespo (Secretary), Jeffrey Newcomb, John Scalzo, Bob Jessee, Keith Fisher, Christen Blend

1. Call to Order

A. Roll Call for Quorum

B. Review of Agenda

2. Kentucky Power Interest in Mitchell Plant

A. Discuss prior orders of the Kentucky and West Virginia Commissions regarding the ownership and operation of the Mitchell Plant after December 31, 2028.

B. Discuss Kentucky Power reinvestment in Mitchell Plant and utilization of capacity and energy from the Mitchell Plant after December 31, 2028.

C. Review the Consent Action adopted by the Committee on September 1, 2022.

D. Discussion of potential Committee actions regarding Kentucky Power reinvestment.

3. Other Business

4. Adjournment

MITCHELL OPERATING COMMITTEE

MINUTES

May 28, 2025

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Plant Operating Agreement (the "Agreement") was held on May 28, 2025, at 1:00 p.m. (Eastern).

Operating Representatives Present:

- Aaron Walker, President and Chief Operating Officer, Wheeling Power Company ("Wheeling Power"),
- Cynthia Wiseman, President and Chief Operating Officer, Kentucky Power Company ("Kentucky Power"), and
- Alex Vaughan, Managing Director, Regulated Pricing – Generation and Fuel Strategy, American Electric Power Service Corporation ("AEPSC"),

constituting all the Operating Representatives. Also present were:

- John Scalzo, Vice President, Regulatory and Finance, Wheeling Power
- Jeffrey Newcomb, Vice President, Regulatory and Finance, Kentucky Power
- John Crespo, Dep. Gen. Counsel, Regulatory & Nuclear, AEPSC
- Bob Jessee, Vice President, Generating Assets – East, Appalachian Power
- Christen Blend, Corp. Sec. and Assoc. Gen. Counsel, AEPSC
- Keith Fisher, Senior Counsel, AEPSC

1. Call to Order

Mr. Crespo acted as Secretary of the Committee. Mr. Crespo presented and on motion duly seconded the Operating Representatives of the Owners, comprising the voting members of the Committee, unanimously approved the agenda for the meeting, attached.

2. Kentucky Power Interest in Mitchell Plant

The Operating Representatives discussed the prior orders of the Kentucky and West Virginia Commissions regarding the ownership and operation of the Mitchell Plant after December 31, 2028.

Ms. Wiseman described Kentucky Power's intention to make the appropriate filings pursuant to Kentucky law and the prior orders of the Kentucky Commission to reinvest in the Effluent Limitations Guidelines ("ELG") control equipment and other equipment at the Mitchell Plant for which Kentucky Power has been allocated less than a 50% share of the costs, as set forth in the Consent Action adopted by the Committee on September 1, 2022, and to continue using its 50% share of the capacity and energy of the Mitchell Plant after December 31, 2028. The Operating Representatives and others present engaged in a general discussion of Kentucky Power's reinvestment and its intention to make the appropriate filings with the Kentucky Commission in June 2025.

The Operating Representatives also reviewed the Minutes of the Committee's January 31, 2024 meeting. The Operating Representatives generally observed that Kentucky Power's actions to reinvest in the Mitchell Plant would satisfy the resolutions set forth in those Minutes to better define the Owners' interests in the Mitchell Plant and to form a mutually acceptable resolution of post-2028 plant ownership and operations.

The Operating Representatives further reviewed the Consent Action adopted by the Committee on September 1, 2022. The Operating Representatives and others present engaged in general discussion of the resolutions contained in the Consent Action that would require modification to facilitate Kentucky Power's reinvestment in the Mitchell Plant. The Operating Representatives will continue to review the modifications which may be required to facilitate Kentucky Power's reinvestment in the Mitchell Plant and to obtain the required regulatory approvals.

3. Other Business

Mr. Walker generally described the West Virginia Commission's May 23, 2025 order directing Wheeling Power and Appalachian Power to file an Integrated Resource Plan (IRP) by October 1, 2025 in accordance with IRP requirements recently enacted by the West Virginia Legislature as part of the Power Generation and Consumption Act of 2025.

4. Adjournment

There being no further business, the Committee meeting was adjourned.

DATA REQUEST

KPSC PHDR_2

Refer to Wolfram Direct Testimony, Exhibit TSW-1.

a.: Explain each basis for the premise that Exhibit TSW-1 or any other agreement involving Kentucky Power would require Kentucky Power to give-up its 50 percent share of the Mitchell Plant, or its right to 50 percent of the energy or capacity from the Mitchell Plant, due to Kentucky Power's failure to pay 50 percent of the capital costs for a given project. Identify in your response the provisions of agreements that support that premise and explain why those provisions support that premise.

b.: If the Commission were to approve Kentucky Power's request herein, explain whether it is Kentucky Power's position that the Commission would be required to approve recovery of any capital project approved by the Mitchell Plant Operating Committee and the West Virginia Commission in order for Kentucky Power to retain its 50 percent share of the Mitchell Plant, or its right to 50 percent of the energy or capacity from the Mitchell Plant, and explain each basis for your response.

c.: Explain whether your response to subpart b. would differ in a circumstance in which the Mitchell Plant Operating Committee and the West Virginia Commission approved a future project with a higher capital cost but which had a longer life whereas the Kentucky Commission found that a project with a lower capital cost and a shorter life would be least-cost.

d.: Confirm that Exhibit TSW-1 and other agreements related to Mitchell Plant allow the Commission to review the prudency of operation and maintenance (O&M) expenses at Mitchell Plant and to make adjustments to the extent such adjustments are supported by the evidence, and explain each basis for your response.

e.: Explain whether changes made to Exhibit TSW-1 and other agreements related to Mitchell Plant that allowed Wheeling Power Company (Wheeling Power) to take over direct operation of the Mitchell Plant from Kentucky Power affect the Commission's ability to conduct prudency reviews of O&M expenses at Mitchell Plant and to make adjustments to the extent such adjustments are supported by the evidence.

RESPONSE

a. The premise that Kentucky Power is not currently entitled to energy and capacity from the Mitchell Plant after December 31, 2028, is based on the Commission's prior orders, specifically those referenced and provided in the Company's response to KPSC 1-1, dictating that Kentucky Power was not authorized to make the ELG investment necessary for the Mitchell Plant to continue operating after December 31, 2028. The September 1, 2022 Written Consent Action of the Mitchell Operating Committee, provided in Exhibit TSW-1, reflects the effects of the Commission's orders and provides the cost allocation amongst Kentucky Power and Wheeling Power to ensure costs associated with the Mitchell Plant are allocated consistent with the Commission's orders. There are no explicit provisions within the Mitchell Plant Operating Agreement concerning the disposition of Kentucky Power's 50% ownership interest in the Mitchell Plant, but the aforementioned Commission orders require the Company's interest in the energy and capacity from the Mitchell Plant to terminate after December 31, 2028.

b. Kentucky Power acknowledges that the Commission has the plenary authority and discretion to approve and/or disapprove costs in a manner consistent with its statutory authority, and it is not Kentucky Power's position that the Commission would be "required" to approve the recovery of future capital costs as a result of approving this application. However, while Kentucky Power cannot anticipate all future needs for capital investment, it is possible that there could be future requirements to file CPCNs that could impact each Plant owner's respective entitlement to energy and capacity, similar to the impacts of the Commission's Orders in Case No. 2021-00004 and Case No. 2021-00421 on Kentucky Power's entitlement to capacity and energy from the Mitchell Plant after December 31, 2028.

c. The Company's response does not change in that scenario. However, such an outcome could have similar effects to the Kentucky and West Virginia Commission's orders with respect to the ELG investment, and the Operating Committee would likely need to determine what impacts those approvals or disapprovals would have on Kentucky Power's or Wheeling Power's respective entitlements to the Mitchell Plant's energy and capacity going forward.

d. The Commission retains the right to review the prudency of all costs for which Kentucky Power seeks cost recovery that are within the Commission's jurisdiction and consistent with its statutory authority. Please see, for example, KRS 278.030, KRS 278.040, KRS 278.190. Nothing in the Commission-approved Mitchell Plant Operating Agreement or the Written Consent Action abrogates that plenary authority.

e. Please see the Company’s response to subpart (d).

Witness: Tanner S. Wolffram

DATA REQUEST

KPSC PHDR_3	Refer to Wolfram Direct Testimony, page 24, Figure TSW-4. a.: State whether the full $20,059,165.36 reflected in Figure TSW-4 as Kentucky Power's cost of service through December 2025 will be recovered from Wheeling Power's customers, and explain each basis for your response. b.: If the Commission were to grant a regulatory asset to be recovered in Kentucky Power's rates for the full $20,059,165.36 reflected in Figure TSW-4, explain how the full $20,059,165.36 will be reimbursed to Wheeling Power's customers through the creation and amortization of a regulatory liability, with or without carrying costs. If any portion of the $20,059,165.36 will not be reimbursed to Wheeling Power's customers, identify those portions that will not be reimbursed and explain why they will not be reimbursed e.g. they were not paid by Wheeling Power customers.

RESPONSE

a. Kentucky Power expects that the estimated $20.1 million will be recovered from Wheeling Power Company's customers as that amount was based on information provided by Wheeling Power Company based on its current recovery mechanism for the ELG project costs.

b. Based on conversations with Wheeling Power Company, it is the Company's understanding that the entire amount will be passed back to its customers, but the exact mechanism for how that will be accomplished has not yet been determined by Wheeling Power.

Witness: Tanner S. Wolffram (subpart a)

Witness: Alex E. Vaughan (subpart b)

DATA REQUEST

KPSC PHDR_4	Refer to the Direct Testimony of Joshua D. Snodgrass, page 8, Figure JDS-3, indicating estimated additional future spending for Cooling Tower Reinforcement of $15,852,410 from April 2025 to December 2025. a. Identify what portions of that amount have not been spent to date. b. Identify any other material changes to the amounts reflected in Figure JDS-3, if any, not including the potential projects discussed in the Supplemental Direct Testimony of Alex E. Vaughn.

RESPONSE

a. Based on the amount spent from May 2025 through the end of October 2025, $10,079,739 of the estimated future spending of $15,852,410 has not been spent.

b. The Company is not aware of any other material changes at this time.

Witness: Joshua D. Snodgrass

DATA REQUEST

KPSC PHDR_5	Refer to the final Order in Case No. 2020-00290 in which the Commission noted that it will not issue a certificate of public convenience and necessity (CPCN) for construction that has been completed prior to the filing of an application for the CPCN, but in which the Commission authorized the inclusion of the plant in service associated with such construction in the revenue requirement calculation. Explain whether a decision that denied the CPCN requested in this matter based on that procedural issue but otherwise determined that the costs at issue were recoverable would affect Kentucky Power's ability to retain its 50 percent share of the capacity and energy from Mitchell Plant.

RESPONSE

The Company respectfully disagrees with the premise of the question and therefore cannot speculate about the effect, if any, that such a "procedural issue" would have on Kentucky Power's share of the capacity and energy from the Mitchell Plant.

The case cited (Case No. 2020-00290) is factually distinguishable. In that case, the utility, Bluegrass Water ("BW"), made improvements to several sewer and water systems that it either owned and operated or recently purchased. After construction was completed, BW sought a declaratory order from the Commission that a CPCN was not required because the improvements were extensions in the ordinary course of business, or, in the alternative, for approval of a CPCN. The Commission determined that a CPCN was required for certain improvements and ultimately declined to grant BW a CPCN for some of the improvements. The Commission explained that "work on most of the construction items identified was completed," meaning that BW violated KRS 278.020(1) by "failing to obtain a CPCN before it began construction on those items." Order at 28, *In The Matter Of: Electronic Application Of Bluegrass Water Utility Operating Company, LLC For An Adjustment Of Rates And Approval Of Construction*, Case No. 2020-00290 (Ky. P.S.C. Aug. 2, 2021).

This is factually distinguishable from the CPCN sought by Kentucky Power in this proceeding. Although the ELG Project has already been constructed, the project was constructed exclusively by Wheeling Power and at its exclusive cost. The ELG Project was not constructed in contravention of any Kentucky statute, regulation, or Commission order. In this case, Kentucky Power seeks to continue receiving capacity and energy from the Mitchell Plant, and to do that, Kentucky Power must make the capital investments (both in the ELG Project and otherwise) consistent with its ownership share.

The BW case stands instead for the proposition that a utility cannot construct facilities and later seek cost recovery for them without the requisite Commission pre-approvals, including a CPCN.

The instant proceeding is instead factually and procedurally similar to the 2013 case where the Commission granted Kentucky Power a CPCN to acquire an undivided 50% interest in the Mitchell Plant. *See* Order at 43, *In the Matter of: Application Of Kentucky Power Company For (1) A Certificate Of Public Convenience And Necessity Authorizing the Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) All Other Required Approvals And Relief*, Case No. 2012-00578 (Ky. P.S.C. Oct. 7, 2013). The Mitchell Plant was constructed and fully operational prior to the Company's application in that case, and the Company sought a CPCN to make the investments necessary to acquire its 50% undivided interest in the Plant. The Commission's order in that case makes no mention of any procedural issue that would affect the Commission's ability to issue the CPCN requested because the Mitchell Plant had already been constructed. The Commission therefore can and should grant the same approvals in this case.

Respondent: Counsel

DATA REQUEST

KPSC PHDR_6	Refer to the November 18, 2025 Hearing Video Transcript (H.V.T.) at 10:13:15-10:15:00. Provide a copy of Kentucky Power's application, once filed or submitted to the federal government, for grant funds from the amounts recently announced by the Department of Energy for coal plants.

RESPONSE

Please see KPCO_R_KPSC_PHDR_6_ConfidentialAttachment1.

Witness: Tanner S. Wolffram

Control Number: 3605-1510

Prime Applicant Eligibility Certification

The prime awardee must meet the applicable eligibility requirements as defined for each Topic below.

Topic Area 1 – Coal Commissioning, Recommissioning, Retrofitting, and Modernization Projects

☐ I am the prime applicant and own or operate the coal-fired generation assets to be constructed or that are currently inactive or scheduled for retirement prior to January 1, 2032.

☒ N/A (I am not applying under this topic area)

Topic Area 2 – Rural Capacity and Energy Affordability Projects

☒ I am the prime applicant and own or operate the coal-fired generation assets to be newly constructed or are otherwise located in rural or remote communities as defined by IIJA §40103(c)(1).

☐ N/A (I am not applying under this topic area)

Name/Title: Scott Osterholt, Managing Director Federal Grants & Broadband
Business Name: American Electric Power
I, the authorized official named above, represent by my signature that I am authorized to certify this information on behalf of the Prime Applicant. I certify under penalty of perjury that the information contained herein is true, accurate, and complete. I understand that false, fictitious, or fraudulent information, misrepresentations, half-truths, or omissions of any material fact , may subject me to criminal, civil, or administrative penalties for fraud, false statements, false claims or others. (18 U.S.C. 1001 and 287, and 31 U.S.C. 3729-.730 and 3801-.3812). I further understand and agree that (1) the statements made herein are material to DOE's eligibility and funding decisions, and (2) I have a responsibility to update this information immediately upon change.
Signature and Date: Signed by: Scott Osterholt 28CD8A2F49654AE 11/10/2025 | 11:46 AM EST

Control Number: 3605-1510

Construction Strategy and Permitting

Mitchell Mechanical Draft Cooling Tower Modernization Project

Site and Permitting Requirements

Wheeling Power Company (WPCo), in collaboration with Kentucky Power Company (KPCo) and Appalachian Power Company (APCo), all subsidiaries of American Electric Power (AEP), proposes to modernize the Mitchell Plant in the rural community of Moundsville, West Virginia. The proposed project will modernize the Mitchell Plant by installing a new, modern mechanical draft cooling tower, replacing the nearly 60-year-old natural draft “Unit 2” cooling tower currently in operation.

The construction strategy for the Mitchell Plant cooling tower upgrade is designed to ensure timely compliance with all federal, state, and local permitting requirements while supporting a safe and efficient construction process. AEP’s environmental team identified potential permits for the project. Possible required permits include:

Permit	Permitting Agency	Estimated Requirements	Review Duration	Estimated Date of Completion
Construction Stormwater General Permit for a Large Construction Activity (disturbing three or more acres)	West Virginia National Pollutant Discharge Elimination System (NPDES)	• Stormwater Pollution Prevention Plan (SWPPP) • Groundwater Protection Plan • Project drawings and topo map • Erosion and sediment (E&S) control plans • Pre- and post-closure drainage maps and calculations • Soil report	6-8 months	Q3 2026
Floodplain Permit	Marshall County	To be determined	6-8 months	Q3 2026
Air Permit	West Virginia Division of Air Quality	To be determined	12 months	Q3 2026

Table 1. Potential permit requirements

Submission dates will be coordinated with the overall project schedule to ensure permits are in place before construction begins. All documents will be prepared in accordance with regulatory guidance. WPCo will track permitting progress using Primavera P6 project management software and take corrective actions, such as providing additional information or revising plans, if permits are delayed or conditions change.

Control Number: 3605-1510

Contains business sensitive, trade secret, proprietary, or otherwise confidential information exempt from public disclosure

Project Title	Mitchell Mechanical Draft Cooling Tower Modernization Project		
Topic Area	Topic 2. Rural Capacity and Energy Affordability Coal Projects		
Applicant Name	Wheeling Power Company		
Applicant Entity Type and Explanation of Eligibility	Large Business, Utility - Coal-Fired Generation Facility		
Project Location(s)	8999 Energy Hwy, Moundsville, WV 26041-4218 1 Riverside Plaza, Columbus, OH 43215-3412		
Proposed System Capacity:	1,600 MW		
Team Member Organizations: Wheeling Power Company (WPCo) - Applicant American Electric Power (AEP) - Partner Kentucky Power Company (KYCo) - Partner Appalachian Power Company (APCo) - Partner			
Senior/Key Personnel and Their Organizations: WPCo: Jeremy Jackson; Joshua Snodgrass; Dan Eaton; Barb Iverson AEP: Grant Patch; Dan Pizzino; Scott Osterholt; Anthony Null APCo/KPCo: Frank Zeroski; Robert Jesse			
Do the proposed awardee and all team members qualify as domestic entities*? X Yes ☐ No			
Points of Contact	**Name**	**Email**	**Phone Number**
Technical Project Manager	Grant Patch	[redacted]	[redacted]
Business Point of Contact	Scott Osterholt	[redacted]	[redacted]
Confidentiality Statement: Notice of Restriction on Use and Disclosure of Information: Pages 1 of the Cover Page, 2-3 and 8 of the Project Narrative, 2-3 of the Financing Narrative, and 1-3 of the Techno-Economic Analysis of these documents may contain business sensitive, trade secrets, proprietary, or otherwise confidential information that is exempt from public disclosure, indicated by highlight. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance or loan or other transaction agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source.			
Total DOE Funding Request ($M)	[redacted]		
Total Non-Federal Cost Share ($M)	[redacted]		
Total Project Costs ($M)	[redacted]		
Total Period of Performance (yrs)	[redacted]		

Current and Pending Support Forms

Mitchell Mechanical Draft Cooling Tower Modernization Project

Notice of Restriction on Use and Disclosure of Information: All pages of this document may contain business sensitive, trade secrets, proprietary, or otherwise confidential information that is exempt from public disclosure. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance or loan or other transaction agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source.

Control Number: 3605-1510

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted]

[redacted], understand that I have been designated as a covered individual by the Federal funding agency and I certify as follows:

1. I am senior/key personnel associated with the Wheeling Power Company / American Electric Power (AEP) / Kentucky Power Company / Appalachian Power project.
2. I am not currently a recipient of current or pending support and have no sponsored activities, awards, and appointments, whether paid or unpaid; provided as a gift with terms or conditions or provided as a gift without terms or conditions; full-time, parttime, or voluntary; faculty, visiting, adjunct, or honorary; cash or in-kind; foreign or domestic; governmental or private-sector; directly supporting my research or indirectly supporting me by supporting students, research staff, space, equipment, or other research expenses to disclose at this time.
3. I certify to the best of my knowledge and belief that the information contained in this Current and Pending Support Disclosure Statement is true, complete, and accurate. I understand that any false, fictitious, or fraudulent information, misrepresentations, half-truths, or omissions of any material fact, may subject me to criminal, civil, or administrative penalties for fraud, false statements, false claims, or otherwise. (18 U.S.C. §§ 1001 and 287, and 31 U.S.C. §§ 3729-3733 and 3801-3812). I further understand and agree that (1) the statements and representations made herein are material to DOE's funding decision, and (2) I have a responsibility to update the disclosures during the period of performance of the award should circumstances change which impact the responses provided above.
4. I certify that, at the time of submission, I am not a party in a malign foreign talent recruitment program.

[redacted]

11/10/2025 | 1:02 PM EST

Date

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted]

[redacted], understand that I have been designated as a covered individual by the Federal funding agency and I certify as follows:

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[redacted]

11/11/2025 | 2:11 PM EST

Date

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted]

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[redacted]

11/17/2025 | 7:40 AM EST

Date

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted]

[redacted], understand that I have been designated as a covered individual by the Federal funding agency and I certify as follows:

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4. I certify that, at the time of submission, I am not a party in a malign foreign talent recruitment program.

[redacted] –

11/11/2025 | 2:33 PM EST

Date

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted]

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4. I certify that, at the time of submission, I am not a party in a malign foreign talent recruitment program.

[redacted]

11/10/2025 | 2:32 PM EST

Date

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted], understand that I have been designated as a covered individual by the Federal funding agency and I certify as follows:

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4. I certify that, at the time of submission, I am not a party in a malign foreign talent recruitment program.

[redacted]

11/10/2025 | 12:59 PM EST

Date

Control Number: 3605-1510

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted]

[redacted], understand that I have been designated as a covered individual by the Federal funding agency and I certify as follows:

1. I am senior/key personnel associated with the Wheeling Power Company / American Electric Power (AEP) / Kentucky Power Company / Appalachian Power project.
2. I am not currently a recipient of current or pending support and have no sponsored activities, awards, and appointments, whether paid or unpaid; provided as a gift with terms or conditions or provided as a gift without terms or conditions; full-time, parttime, or voluntary; faculty, visiting, adjunct, or honorary; cash or in-kind; foreign or domestic; governmental or private-sector; directly supporting my research or indirectly supporting me by supporting students, research staff, space, equipment, or other research expenses to disclose at this time.
3. I certify to the best of my knowledge and belief that the information contained in this Current and Pending Support Disclosure Statement is true, complete, and accurate. I understand that any false, fictitious, or fraudulent information, misrepresentations, half-truths, or omissions of any material fact, may subject me to criminal, civil, or administrative penalties for fraud, false statements, false claims, or otherwise. (18 U.S.C. §§ 1001 and 287, and 31 U.S.C. §§ 3729-3733 and 3801-3812). I further understand and agree that (1) the statements and representations made herein are material to DOE's funding decision, and (2) I have a responsibility to update the disclosures during the period of performance of the award should circumstances change which impact the responses provided above.
4. I certify that, at the time of submission, I am not a party in a malign foreign talent recruitment program.

[redacted]

11/10/2025 | 2:07 PM EST

Date

Control Number: 3605-1510

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted]

[redacted] Mitchell Plant, understand that I have been designated as a covered individual by the Federal funding agency and I certify as follows:

1. I am senior/key personnel associated with the Wheeling Power Company / American Electric Power (AEP) / Kentucky Power Company / Appalachian Power project.
2. I am not currently a recipient of current or pending support and have no sponsored activities, awards, and appointments, whether paid or unpaid; provided as a gift with terms or conditions or provided as a gift without terms or conditions; full-time, parttime, or voluntary; faculty, visiting, adjunct, or honorary; cash or in-kind; foreign or domestic; governmental or private-sector; directly supporting my research or indirectly supporting me by supporting students, research staff, space, equipment, or other research expenses to disclose at this time.
3. I certify to the best of my knowledge and belief that the information contained in this Current and Pending Support Disclosure Statement is true, complete, and accurate. I understand that any false, fictitious, or fraudulent information, misrepresentations, half-truths, or omissions of any material fact, may subject me to criminal, civil, or administrative penalties for fraud, false statements, false claims, or otherwise. (18 U.S.C. §§ 1001 and 287, and 31 U.S.C. §§ 3729-3733 and 3801-3812). I further understand and agree that (1) the statements and representations made herein are material to DOE's funding decision, and (2) I have a responsibility to update the disclosures during the period of performance of the award should circumstances change which impact the responses provided above.
4. I certify that, at the time of submission, I am not a party in a malign foreign talent recruitment program.

[redacted]

11/11/2025 | 6:39 AM EST

Date

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower

Senior/Key Personnel: [redacted]

[redacted], understand that I have been designated as a covered individual by the Federal funding agency and I certify as follows:

1. I am senior/key personnel associated with the Wheeling Power Company / American Electric Power (AEP) / Kentucky Power Company / Appalachian Power project.
2. I am not currently a recipient of current or pending support and have no sponsored activities, awards, and appointments, whether paid or unpaid; provided as a gift with terms or conditions or provided as a gift without terms or conditions; full-time, parttime, or voluntary; faculty, visiting, adjunct, or honorary; cash or in-kind; foreign or domestic; governmental or private-sector; directly supporting my research or indirectly supporting me by supporting students, research staff, space, equipment, or other research expenses to disclose at this time.
3. I certify to the best of my knowledge and belief that the information contained in this Current and Pending Support Disclosure Statement is true, complete, and accurate. I understand that any false, fictitious, or fraudulent information, misrepresentations, half-truths, or omissions of any material fact, may subject me to criminal, civil, or administrative penalties for fraud, false statements, false claims, or otherwise. (18 U.S.C. §§ 1001 and 287, and 31 U.S.C. §§ 3729-3733 and 3801-3812). I further understand and agree that (1) the statements and representations made herein are material to DOE's funding decision, and (2) I have a responsibility to update the disclosures during the period of performance of the award should circumstances change which impact the responses provided above.
4. I certify that, at the time of submission, I am not a party in a malign foreign talent recruitment program.

[redacted]

11/10/2025 | 4:10 PM EST

Date

Control Number: 3605-1510

Current and Pending Support

Project Title: Mitchell Mechanical Draft Cooling Tower Modernization Project

Senior/Key Personnel: [redacted]

[redacted], understand that I have been designated as a covered individual by the Federal funding agency and I certify as follows:

1. I am senior/key personnel associated with the Wheeling Power Company project.
2. [redacted]
3. I certify to the best of my knowledge and belief that the information contained in this Current and Pending Support Disclosure Statement is true, complete, and accurate. I understand that any false, fictitious, or fraudulent information, misrepresentations, half-truths, or omissions of any material fact, may subject me to criminal, civil, or administrative penalties for fraud, false statements, false claims, or otherwise. (18 U.S.C. §§ 1001 and 287, and 31 U.S.C. §§ 3729-3733 and 3801-3812). I further understand and agree that (1) the statements and representations made herein are material to DOE's funding decision, and (2) I have a responsibility to update the disclosures during the period of performance of the award should circumstances change which impact the responses provided above.
4. I certify that, at the time of submission, I am not a party in a malign foreign talent recruitment program.

Current Active Funding						
Source of Funding	Award Number	Title of the Award Project	Description	Total Project Cost	Award Period (start-end dates)	Person-months of effort/ year
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

			[redacted]			
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

			[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

AMERICAN ELECTRIC POWER

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

AMERICAN ELECTRIC POWER

Control Number: 3605-1510

[redacted]			[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pending Awards						
Source of Funding	**Award Number**	**Title of the Award Project**	**Description**	**Total requested funding**	**Award Period (start-end dates)**	**Person-months of effort/ year**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 1. Current and Pending Support – [redacted]

[redacted]

11/10/2025 | 11:46 AM EST

Date

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Evidence of Offtake or Load Agreements

Mitchell Mechanical Draft Cooling Tower Modernization Project

The Mitchell Plant, jointly owned by Wheeling Power Company and Kentucky Power Company, serves as a key energy resource for both utilities.

Wheeling Power Company:
Below is a summary of customers' highest-previous demand (HPD) data for Wheeling Power. Personal customer information has been removed to maintain anonymity.

Account	HPD (kW)
Customer A1	133,600
Customer A2	69,311
Customer A3	65,764
Customer A4	49,775
Customer A5	40,000
Customer A6	35,372
Customer A7	35,102
Customer A8	32,208
Customer A9	29,760
Customer A10	24,246
Customer A11	23,888
Customer A12	23,880
Customer A13	22,764
Customer A14	21,450
Customer A15	19,647
Customer A16	19,056
Customer A17	17,352
Customer A18	16,730
Customer A19	16,308
Customer A20	14,994
Customer A21	9,563
Customer A22	7,812
Customer A23	6,415
Customer A24	4,738
Customer A25	4,414
Customer A26	3,595
Customer A27	2,930
Customer A28	2,798
Customer A29	2,202
Customer A30	2,183
Customer A31	2,083
Customer A32	1,822
Customer A33	1,587
Customer A34	1,490
Customer A35	1,398
Customer A36	1,396
Customer A37	1,190
Customer A38	1,180
Customer A39	1,152
Customer A40	1,069

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Table 1. Customers' (anonymous) highest-previous demand (HPD) data

Kentucky Power Company
Below is a list of customers for Kentucky Power Company, derived from publicly available contract filings on the Kentucky Public Service Commission (PSC) website. For full documentation and additional contract details, you may refer to the company's "Contracts" section in the PSC tariff library[1].

Air Products and Chemicals Inc
Ashland Hospital Corporation dba Kings Daughters Medical Center
Big Run Power Producers, LLC
Big Sandy RECC
Blue Diamond Mining
Boyd County Board of Education
Carter County Board of Education
City of Allen
City of Ashland
City of Catlettsburg
City of Elkhorn City
City of Flatwoods
City of Grayson
City of Greenup
City of Hazard
City of Hyden
City of Jackson
City of Jenkins
City of Louisa
City of Martin
City of Neon
City of Olive Hill
City of Paintsville
City of Pikeville
City of Prestonsburg
City of Raceland
City of Russell
City of Salyersville
City of South Shore
City of Vanceburg
City of Vicco
City of West Liberty
City of Wheelwright
City of Whitesburg
City of Worthington
Clintwood JOD, LLC
Coals, Inc. Princess Elkhorn Coal Division
Consol of Kentucky, Inc
Cyber Innovation Group
Dajcor Aluminum
Deane Mining LLC
Discover AI, LLC
East Kentucky Power Company
Emperor Coal Company
EQT Gathering, LLC
Grayson RECC
High Ridge Mining, LLC
Inez Power, LLC
Island Creek Coal Company
Kentucky Department of Highways
Kentucky Electric Steel Corporation
KES Acquisition Company, LLC
Kings Daughters Medical Center
Letcher County Board of Education
Louisa Baptist Church
M C Mining Inc
Martin County Board of Education
McCoy Elkhorn Coal LLC
Northeast Kentucky Regional Industrial Park Authority
Our Lady of Bellefonte Hospital
Perry County Board of Education
Pike County Board of Education
Pole Joint Use Agreement
SWVA Kentucky, LLC
The Tierney Corporation
Town of Fleming
Town of Hindman
Town of Van Lear
Town of Wayland
US Army Corps of Engineers

[1] Kentucky Power Company Tariffs Library. Kentucky Public Service Commission. https://psc.ky.gov/Home/Library?type=Tariffs&folder=Electric%5CKentucky%20Power%20Company%5CContracts

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US Army Corps of Engineers - Huntington
Wal-Mart Stores, Inc

Control Number: 3605-1510

Financing

Mitchell Mechanical Draft Cooling Tower Modernization Project

Pages 2-3 of this document may contain business sensitive, trade secret, proprietary, or otherwise confidential information that is exempt from public disclosure, as indicated by highlight. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance, loan, or Other Transaction Agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source.

Financing Strategy

Wheeling Power Company (WPCo), in collaboration with Kentucky Power Company (KPCo) and Appalachian Power Company (APCo), all subsidiaries of American Electric Power (AEP), proposes to modernize the Mitchell Plant in the rural community of Moundsville, West Virginia. The proposed project will modernize the Mitchell Plant by installing a new, modern mechanical draft cooling tower, replacing the nearly 60-year-old natural draft "Unit 2" cooling tower currently in operation.

Funding provided by the Department of Energy (DOE), covering about 30% of total project costs, is instrumental in de-risking and accelerating the project. DOE funding would alleviate the strain on the internal budget, enabling the timely procurement of essential materials and labor, and minimizing cash flow-related delays. This flexibility would help maintain the project schedule and allow the new cooling tower to come online sooner, ensuring the delivery of reliable and affordable energy to ratepayers while effectively managing cost, performance, and operational risks.

Milestones

The project milestones selected for the Mitchell Plant cooling tower upgrade will track progress toward a fully operational mechanical draft cooling tower capable of reliably sustaining the plant's full generation capacity of 1,600 megawatts (MW) and preventing the potential loss of up to 800 MW of generation capacity. These milestones align with critical technical and construction activities, with certain milestones proposed as cost-shared under this award due to their importance in ensuring project success. Proposed cost-shared milestones include engineering and design, procurement of the mechanical draft cooling tower, and piping for tie-in. These activities represent the most significant and high-risk components of the project, directly impacting the project's performance objectives.

AMERICAN ELECTRIC POWER

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Activity or Milestone Go/No-Go (GNG)	Milestone Description	Start Date	End Date	Cost ($M)	Applicant Cost Share ($M)	DOE Funds ($M)	Project Costs to Date ($M)	% DOE Share to Date
Phase 1: Site Control Confirmation; Engineering and Design		Q4 2025	Q1 2027					
Functional engineering		*Q4 2025*	*Q3 2026*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Detailed design		Q3 2026	Q1 2027					
Milestone/GNG: Final design package complete	Complete and final design package approved		Q1 2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Phase 2: Procurement and Permitting		Q3 2026	Q4 2027					
Equipment and materials purchased		Q3 2026	Q4 2027	[redacted]	[redacted]	[redacted]	[redacted]	
Milestone/GNG: Cooling tower on site	Delivery and installation of tower onsite	Q1 2027	Q4 2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Phase 3: Construction		Q2 2027	Q2 2028					
Milestone/GNG: Ground taken to grade; civil construction complete	All civil work in relation to the project has been substantially completed for next stages	Q2 2027	Q3 2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Milestone/GNG: Mechanical and electrical install	All mechanical and electrical work in relation to the project has been substantially completed for next stages	Q3 2027	Q1 2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Removal of cooling tower water system for tie-in to new system		Q1 2028	Q2 2028	[redacted]	[redacted]	[redacted]	[redacted]	
Milestone/GNG: Construction complete	Tower and mechanical systems installed per design		Q2 2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Phase 4: Testing and In-Service		Q2 2028	Q3 2028					
System testing and commissioning		Q2 2028	Q3 2028	[redacted]	[redacted]	[redacted]	[redacted]	
Overall Project Management								
Contingency Costs	Allocated to above phases					[redacted]	[redacted]	
Owner's Indirect Costs				[redacted]	[redacted]	[redacted]	[redacted]	
			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Table 1. Milestone and cost summary. *As described in the Project Narrative, [redacted] of preliminary project costs are not included in the proposed budget as they will take place before the anticipated DOE award date.*

Milestone progress will be tracked by Project Controls using Primavera P6 to monitor schedule adherence, budget spend, and milestone completion. If a milestone is anticipated to be delayed, corrective actions will include reallocating resources, accelerating subsequent activities where possible, and engaging with vendors or contractors to mitigate schedule risks. A detailed milestone payment breakdown and project spend plan are under development and will be finalized by Q1 2026.

Project Cost

WPCo and KPCo will recover the non-federal share of the project costs from customers through their electric service rates, as applicable. WPCo and KPCo, the owners of the Mitchell Plant, will capitalize the balance of the project costs through a combination of debt and equity financing.

Control Number: 3605-1510

Documentation from Potentially Impacted Indian Tribes

Mitchell Mechanical Draft Cooling Tower Modernization Project

Project Description

The proposed initiative aims to modernize a coal power plant in Moundsville, West Virginia, by installing an upgraded mechanical cooling tower to maintain its operational output. Given that this is an existing facility rather than new construction, there are no anticipated impacts on Tribal land or resources.

Project Location

The proposed activities will be conducted at: 8999 Energy Hwy, Moundsville, WV 26041.

Justification for No Impact Determination

The project site is located on private property and falls outside the boundaries of any federally recognized Indian tribal lands (see Figure 1). Based on the project scope and location, no direct, indirect, or cumulative impacts to Tribal lands, resources, or interests are anticipated. The proposed activities will occur entirely on non-Tribal property, involve no ground disturbance, and do not affect known or potential historic or cultural sites. Accordingly, this project is expected to have no impact on Indian Tribes or Tribal resources. The attached map shows the proposed project site overlaid with the Bureau of Indian Affairs' "Indian Lands" GIS dataset, confirming that the site is on non-Tribal land and outside federally recognized trust lands or reservations. Therefore, the project will not impact trust lands or areas of Tribal jurisdiction.

As the activities will only occur on non-Tribal property and will not disturb Tribal lands or affect historic or cultural sites, the project is expected to have no impact on Indian tribes, resources, or subsurface rights.

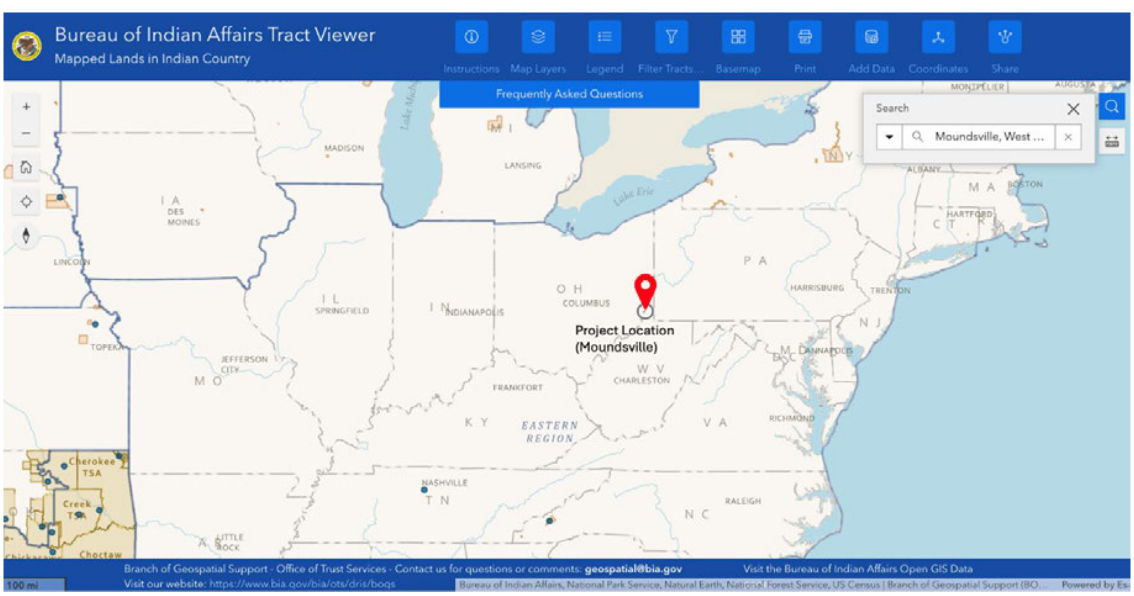

Figure 1. Map sources from the Bureau of Indian Affairs' "Indian Lands" GIS dataset

Control Number: 3605-1510

Letters of Commitment
Mitchell Mechanical Draft Cooling Tower Modernization Project

Notice of Restriction on Use and Disclosure of Information: Pages 2-3 of this document may contain business sensitive, trade secrets, proprietary, or otherwise confidential information that is exempt from public disclosure, as indicated by highlight. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance or loan or other transaction agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source.

 Control Number: 3605-1510

11/11/2025
The Honorable Chris Wright
Secretary of Energy
Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585

Dear Secretary Wright,

As a company deeply invested in the well-being of our local area, I am writing to affirm our commitment to the construction of a mechanical draft cooling tower at Mitchell Power Plant, a coal-fired power plant in the rural community of Moundsville, West Virginia. Our organization recognizes that resilient and reliable energy infrastructure is essential for the prosperity and safety of our community.

The project aims to construct a new mechanical draft cooling tower to replace the compromised natural draft cooling tower currently onsite at the Mitchell Power. This project will allow the plant to continue performing at maximum capacity while generating the needed power in our community. Wheeling Power will lead the project implementation and activities. Our organization will partner with Kentucky Power, Appalachian Power Company, and American Electric Power (AEP) to successfully implement this project.

[redacted]

Should you require additional information or wish to discuss our partnership further, please feel free to contact me at awalker@aep.com.

Sincerely,

Signed by:
1E95B37AA7AE40C...

Aaron Walker
President and CEO
APCO

Control Number: 3605-1510

11/11/2025
The Honorable Chris Wright
Secretary of Energy
Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585

Dear Secretary Wright,

As a company deeply invested in the well-being of our local area, I am writing to affirm our commitment to collaboration and engagement for the construction of a mechanical draft cooling tower at Mitchell Power Plant, a coal-fired power plant in the rural community of Moundsville, West Virginia. Our organization recognizes that resilient and reliable energy infrastructure is essential for the prosperity and safety of our community. The project aims to construct a new mechanical draft cooling tower to replace the compromised natural draft cooling tower currently onsite. This project will allow Mitchell Plant to continue performing at maximum capacity while generating the needed power in our community. In alignment with these goals, our organization will partner with Wheeling Power to successfully implement this project.

- Kentucky Power Company supports Mitchell Plant with this project to improve its reliability and capacity. This aligns with Kentucky Power Company's core values as a company by supporting local communities, providing unique power solutions to our customers, and scaling technological advances within the generation infrastructure.
- Kentucky Power Company has expertise in providing energy for customers to meet challenging demands that include reduction in energy consumption, rising energy costs, and decrease carbon emissions. Kentucky Power Company is experienced in providing innovative approaches and in assisting with the implementation of challenging and complex projects.
- Kentucky Power Company recognizes during sustained outages, communities become vulnerable without access to power. Kentucky Power Company believes in the development of long term solutions in generating power to meet the reliability and capacity needs of our communities. By supporting long term solutions, we look to minimize outages.

[redacted] Should you require additional information or wish to discuss our partnership further, please feel free to contact me at cgwiseman@aep.com.

Sincerely,

Signed by:
Cynthia Wiseman
1E6D742C7C0D4F1...

Cynthia Wiseman
President & COO
Kentucky Power Company

Control Number: 3605-1510

11/11/2025
The Honorable Chris Wright
Secretary of Energy
Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585

Dear Secretary Wright,

As a community partner deeply invested in the well-being of our local area, I am writing to affirm our commitment to collaboration and engagement for the construction of a mechanical draft cooling tower at Mitchell Plant, a coal-fired power plant in the rural community of Moundsville, West Virginia. Our organization recognizes that resilient and reliable energy infrastructure is essential for the prosperity and safety of our community.

The project aims to construct a new mechanical draft cooling tower to replace the compromised natural draft cooling tower currently onsite. This project will allow Mitchell Plant to continue performing at maximum capacity while generating the needed power in our community. In alignment with these goals, our organization will partner with Kentucky Power, Wheeling Power, and American Electric Power to successfully implement this project.

- Appalachian Power Company supports Mitchell Plant with this initiative to improve the plant's reliability and capacity. This aligns with Appalachian Power Company's core values as a company by supporting local communities, providing unique power solutions to our customers, and scaling technological advances within the generation infrastructure.
- Appalachian Power Company has expertise in providing energy for customers to meet challenging demands that include reduction in energy consumption, rising energy costs, and decrease carbon emissions. Appalachian Power Company is experienced in providing innovative approaches and in assisting with the implementation of challenging and complex projects.
- Appalachian Power Company recognizes during sustained outages, communities become vulnerable without access to power. Appalachian Power Company believes in the development of long-term solutions in generating power to meet the reliability and capacity needs of our communities. By supporting long term solutions, we look to minimize outages.

Should you require additional information or wish to discuss our partnership further, please feel free to contact me at awalker@aep.com.

Sincerely,

Signed by:
1E95B37AA7AE40C...

Aaron Walker
President & COO
Appalachian Power Company

Control Number: 3605-1510

AMERICAN ELECTRIC POWER

11/11/2025
The Honorable Chris Wright
Secretary of Energy
Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585

Dear Secretary Wright,
As a community partner deeply invested in the well-being of our local area, I am writing to affirm our commitment to collaboration and engagement for the construction of a mechanical draft cooling tower at Mitchell Plant, a coal-fired power plant in the rural community of Moundsville, West Virginia. Our organization recognizes that resilient and reliable energy infrastructure is essential for the prosperity and safety of our community.

The project aims to construct a new mechanical draft cooling tower to replace the compromised natural draft cooling tower currently onsite. This project will allow Mitchell Plant to continue performing at maximum capacity while generating the needed power in our community. In alignment with these goals, our organization will partner with Wheeling Power, Kentucky Power, and Appalachian Power Company to successfully implement this project.

- American Electric Power (AEP) supports Mitchell Plant with this initiative to improve the plant's reliability and capacity. This aligns with AEP's core values as a company by supporting local communities, providing unique power solutions to our customers, and scaling technological advances within the generation infrastructure.
- AEP has expertise in providing energy for customers to meet challenging demands that include reduction in energy consumption and rising energy costs. AEP is experienced in assisting with the implementation of challenging and complex power generation projects.
- AEP recognizes that during sustained outages, communities become vulnerable without access to power. AEP believes in the development of long-term solutions in generating power to meet the reliability and capacity needs of our communities. By supporting long-term solutions, we look to minimize outages.

Should you require additional information or wish to discuss our partnership further, please feel free to contact me at bfehrman@aep.com.

Sincerely,

Bill Fehrman

Bill Fehrman
Chair, President & CEO
AEP

Control Number: 3605-1510

Management Team and Project Partners

Mitchell Mechanical Draft Cooling Tower Modernization Project

Primary Project Team

Teaming Partner	Roles and Responsibilities	% of Effort
Wheeling Power Company (WPCo)	Applicant, site co-owner, project lead, cost share provider, and overall project management	40%
American Electric Power (AEP)	Project management, engineering leadership, and oversight of construction activities, including planning, scheduling, contract administration, and on-site coordination and supervision	40%
Appalachian Power Company (APCo)	Operating corporate partner providing budgetary oversight	10%
Kentucky Power Company (KPCo)	Site co-owner and cost share provider	10%

Table 1. Project team partners (companies)

Key Personnel

Mitchell Plant personnel have various other roles and responsibilities, but they will provide the time commitment necessary to ensure this project's success and provide the grant team with the required information for reporting.

Name, Title	Company	Project Roles and Responsibilities	Expertise	% Time Commitment
Dan Eaton, Maintenance Superintendent Senior	Wheeling Power Company	Technical support	Maintenance and engineering professional with extensive experience in the utility sector; expertise in outage planning and execution, ensuring compliance with safety and regulatory standards	20%
Barb Iverson, Administrative Supervisor Senior	Wheeling Power Company	Monitoring and maintaining budget	Skilled supervisor in receiving, inventory management, invoicing, and catalog management	15%
Jeremy Jackson, Interim Maintenance Supervisor	Wheeling Power Company	Site lead	19 years of experience in power plant maintenance and supervision, managing large teams, and coordinating across facilities	40%
Joshua Snodgrass, Plant Manager, Mitchell Plant	Wheeling Power Company	Staffing and resource management; oversee business plans and site finances	20+ years of experience as a plant manager and supervisor in energy production and maintenance leadership, specializing in operational efficiency, safety initiatives, budgeting, outage coordination, and continuous improvement across multiple AEP facilities	25%

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Scott Osterholt, Managing Director, Federal Grants and Broadband (Business Contact)	AEP	Federal funding and grant compliance	30+ years at AEP, securing federal funds to support multi-billion-dollar infrastructure projects; extensive expertise advancing grid modernization, new technology deployment, telecom network operations, and grant management	10%
Grant Patch, Senior Project Manager, Generation and Distribution (Project Lead)	AEP	Site project manager	9+ years of experience in coal-fired power plants, distribution, transmission, right of way, and electrical/lighting wholesale	80%
Dan Pizzino, Director, Civil Engineering	AEP	Project engineering lead	20+ years in civil and structural engineering experience with a strong track record in power generation project development, technical team management, and regulatory compliance	50%
Anthony Null, Site Construction Manager	AEP	Construction planning and supervision	Oversees safe, reliable, compliant, and cost-effective operations of fossil-fueled and hydro assets across multiple plants; coordinates operations, maintenance, engineering, construction, and budgeting with AEP functional groups	80%
Robert Jesse, VP Generation Assets	Appalachian Power Company	Oversight of generation assets	29+ years of Power Generation Industry experience; 15+ years in a leadership role, with responsibility for overseeing and directing the activities of facility employees and contractors	15%
Frank Zeroski, Budget Analyst Staff	Appalachian Power	Operating corporate company budgetary information lead contact responsible for coordinating the budget for both KPCo and WPCo	Extensive expertise in managing multimillion-dollar operations and capital budgets, aligning financial data with regulatory filings, and developing complex reporting tools	25%

Table 2. Key personnel

Past Performance

A previous key initiative with a comparable scope to the proposed project was the Unit 2 Components Upgrade, which took place at the Mitchell Plant in 2021. This project enhanced existing cooling tower infrastructure by upgrading the hot water deck and supports, circumferential and radial basin walls, and splash boxes, including flow control valve, pipe saddles and supports, louvers, louver columns, circumferential girts, fill and grid (partial), ice screens, outer walkway, and canopy deck with crossover bridges. The work was completed in collaboration with contractors SPX Cooling Tech, LLC (a cooling tower vendor) and Worley Parsons (an engineering firm), which the team intends to engage for competitive pricing for the proposed mechanical draft cooling tower project. This Unit 2 upgrade was also executed during a constrained outage. It was completed on time (2021-2022) and within the $10M project budget.

Another significant project with a comparable scope was the Mitchell Coal Combustion Residuals (CCR) and Effluent Limitation Guidelines (ELG) Compliance initiative in 2024, an environmental program implemented to ensure Department of Energy (DOE) compliance. Activities consisted of bottom ash conversion, pond closure and repurposing, and flue-gas desulfurization wastewater treatment. The project team collaborated with several contractors supporting the scope of activities, including Worley Parsons. It was completed on time (2020-2024) and within the $175M project budget.

Engagement with Regulators and Other Relevant Community Stakeholders

AEP will work in collaboration with our local operating companies to manage awarded funds and coordinate with the DOE to ensure that all customers understand the impact the grant award will have on affordability and reliability. Additionally, we may conduct targeted outreach to regulators and policymakers to share information as appropriate. We have celebrated previous grant awards and loan closings, resulting in positive coverage and communication to relevant communities through local media.

AMERICAN ELECTRIC POWER

Control Number: 3605-1510

Potentially Duplicative Funding Notice

Notice of Restriction on Use and Disclosure of Information: All pages of this document may contain business sensitive, trade secrets, proprietary, or otherwise confidential information that is exempt from public disclosure. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance or loan or other transaction agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source.

[redacted] am a participating Key Personnel member on the following application to (BAA) Solicitation Number: DE-FOA-0003605, Restoring Reliability: Coal Recommissioning and Modernization:

Applicant: Wheeling Power Company
Project Title: Mitchell Mechanical Draft Cooling Tower Modernization Project

I will serve as an administrative Business Point of Contact for the application. I certify to the best of my knowledge at this time that I will have no direct role in project planning or implementation activities. As an administrative point of contact for federal awards at AEP, my time is allocated as indicated across the current and pending funding awards listed in Table 1. I certify that, to the best of my knowledge, there will be no overlap in funded activities across the DE-FOA-0003605 project or other projects for current or pending applications, and that project funds will not be used (in whole or in part) for any identical cost items.

[redacted]

Sincerely,

Signed by:
[redacted]

[redacted]
Managing Director, Federal Grants and Broadband
AEP

Current Active Funding						
Source of Funding	Award Number	Title of the Award Project	Description	Total Project Cost	Award Period (start-end dates)	Person-months of effort/ year
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Control Number: 3605-1510

CONTAINS BUSINESS SENSITIVE, TRADE SECRET, PROPRIETARY, OR OTHERWISE CONFIDENTIAL INFORMATION EXEMPT FROM PUBLIC DISCLOSURE

			[redacted]			
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

AMERICAN ELECTRIC POWER

Control Number: 3605-1510

CONTAINS BUSINESS SENSITIVE, TRADE SECRET, PROPRIETARY, OR OTHERWISE CONFIDENTIAL INFORMATION EXEMPT FROM PUBLIC DISCLOSURE

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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] – [redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] – [redacted]	[redacted]
[redacted]	[redacted]	[redacted] – [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Control Number: 3605-1510

[redacted]			[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pending Awards						
Source of Funding	**Award Number**	**Title of the Award Project**	**Description**	**Total requested funding**	**Award Period (start-end dates)**	**Person-months of effort/ year**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

		[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 1. Current and Pending Support – [redacted]

Project Narrative

Mitchell Mechanical Draft Cooling Tower Modernization Project

Pages 2-3 and 8 of this document may contain business sensitive, trade secret, proprietary, or otherwise confidential information that is exempt from public disclosure, as indicated by highlight. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance, loan, or Other Transaction Agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source.

Project Concept

Wheeling Power Company (WPCo), in collaboration with Kentucky Power Company (KPCo) and Appalachian Power Company (APCo), proposes to modernize the Mitchell Plant in the rural community of Moundsville, West Virginia. WPCo, KPCo, and APCo—American Electric Power (AEP) subsidiaries—serve approximately 1.25M customers across West Virginia, Kentucky, Virginia, and Tennessee. As a coal-fired generation facility, the Mitchell Plant contributes to the region’s energy resilience and reliable, affordable, and secure generation resources. The plant is equipped with advanced pollution-control technologies, demonstrating the facility’s commitment to reducing emissions and providing reliable energy with improved environmental performance. It also plays a crucial role in sustaining the local economy by providing stable, high-wage employment for 167 full-time staff members in a rural, remote area.

The proposed project will modernize the Mitchell Plant by installing a new, modern mechanical draft cooling tower, replacing the nearly 60-year-old natural draft “Unit 2” cooling tower currently in operation, which requires significant repair and upgrades. This modernization effort is essential to sustain and maintain the plant’s full generation capability of approximately 1,600 megawatts (MW) and to prevent the potential loss of up to 800 MW of capacity if the existing tower fails or becomes inoperable. This critical modernization upgrade will enhance regional grid reliability and significantly reduce outage risk by eliminating reliance on aging infrastructure. Installing a mechanical draft cooling tower provides a robust solution with a lifespan exceeding 25 years, ensuring safe and efficient plant operation, directly improving system reliability and regional energy affordability. Other contemplated options, such as piecemeal upgrades on the aging infrastructure, could ultimately cost customers hundreds of millions of dollars more than the proposed mechanical draft cooling tower and result in the premature closure of the facility.

Project Approach

The project will be executed through a structured, phased approach to ensure timely completion. Phases may overlap when it is feasible to optimize the schedule and maintain project momentum.

Phase 1: Engineering and Design

Preliminary engineering activities will occur prior to the anticipated release of Department of Energy (DOE) grant funding in Q2 2026. Conceptual and functional engineering will begin in Q4 2025 and continue through Q1 2026 to establish project feasibility, scope definition, and baseline design parameters. WPCo anticipates contracting Worley Parsons for engineering, design, and construction support. The proposed project budget does not include these initial costs [redacted]. These early activities will position the project for an efficient transition into DOE-supported phases upon award.

Detailed engineering design, including civil, mechanical, structural, and electrical systems, is scheduled to begin in Q3 2026 and is anticipated to be completed in Q1 2027. The main deliverables for this phase will be construction drawings, revised cost estimates, and a comprehensive project execution plan.

Phase 2: Procurement and Permitting

This phase will focus on environmental and construction permitting, as well as the procurement of long-lead materials and equipment. All major components will be sourced domestically, including the prefabricated mechanical draft cooling tower structure, piping, steel, insulation, electrical components, coatings, and scaffolding.

Phase 3: Construction

This phase will begin with demolition and removal of the out-of-service coal conveyor and coal rail car dumper currently occupying the proposed cooling tower site. All demolition work will be executed in accordance with safety and environmental protocols, ensuring the protection of surrounding infrastructure and personnel. Following demolition, the site will be prepared for installation, and the ground will be taken to grade. This phase will also involve the delivery and staging of tower components, as well as other key materials and equipment. The construction of the new mechanical draft cooling tower will include assembly of prefabricated components, installation of mechanical and electrical systems, piping tie-ins, and integration with existing plant systems. Construction will be conducted by an outside firm utilizing domestic union workers, selected during a request for proposal (RFP) process. The project is expected to generate approximately 50-75 construction jobs, with final staffing levels to be determined by the contractor's execution plan once the project is awarded.

Phase 4: Testing and In-Service

The project will utilize a planned plant outage to complete final tie-in activities, minimizing operational disruptions. The final phase will also include system testing, commissioning, and performance verification to ensure full operational capability. The new mechanical draft cooling tower is scheduled to be placed in service by the end of 2028.

The planned project phases are summarized in the table below.

Phase	Estimated Start Date	Estimated End Date
Engineering and Design	Q2 2026*	Q1 2027
Procurement and Permitting	Q3 2026	Q4 2027
Construction	Q2 2027	Q3 2028
Testing and In-Service	Q2 2028	Q3 2028

*Table 1. Project phases with estimated completion dates. *As described above, preliminary engineering will begin in Q4 2025*

The following table summarizes the proposed total anticipated project costs by major categories.

Cost Category	Justification	Estimated Cost (M)
Personnel / Internal Labor	Labor utilization within AEP	[redacted]
Personnel / Contracted Outside Services	Labor utilization outside AEP	[redacted]
Personnel / Contracted Construction Labor	Third-party companies for specific, project-based construction jobs	[redacted]
Equipment and Supplies	Major items needed in field to complete scope of work	[redacted]
Contingency	About 10-13% of the budget set aside to cover unexpected costs that may arise, which is set to become risk-based as project progresses	[redacted]
Owner's Indirect Costs	General expenses for overhead costs, which are calculated at 18% of non-contingency project costs. Indirect costs are estimated rates published in Q1 each year that AEP uses as the basis for allocations and Allowance for Funds Used During Construction (AFUDC)	[redacted]
	TOTAL	[redacted]

Table 2. Summary of overall project costs. Note that this total includes the estimated $3.5M of pre-award preliminary engineering costs

Project Site

The Mitchell Plant is in Moundsville, WV (population approximately 8,000), with a total generation capacity of approximately 1,600 MW. It consists of multiple generating units, primarily using bituminous coal. Throughout its history, the plant has undergone various upgrades to reduce emissions and comply with environmental standards. This includes coal combustion residuals regulations, effluent limitations guidelines, flue gas desulfurization, selective catalytic reduction, and compliance with the mercury and air toxins standards. See Figure 1 for a detailed schematic of the facility; a full-size image is available upon request.

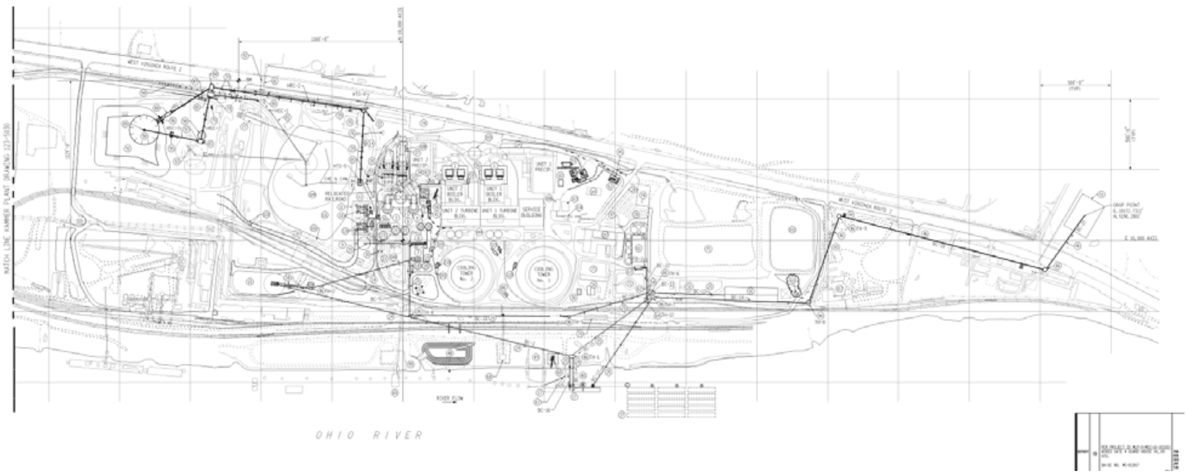

Figure 1. Mitchell plant site plan

WPCo and KPCo are co-owners of the Mitchell Plant, each owning a 50% undivided interest in the plant. Both companies are wholly owned subsidiaries of AEP. As co-owner, WPCo has joint control and management responsibilities over the site.

Technology Selection

The primary technology for this project is a mechanical draft cooling tower, a specialized type of heat exchanger in which air and water are brought into direct contact to reduce the temperature of the circulating water. As this process occurs, a small portion of the water evaporates, extracting heat and cooling the remaining water before it is recirculated.

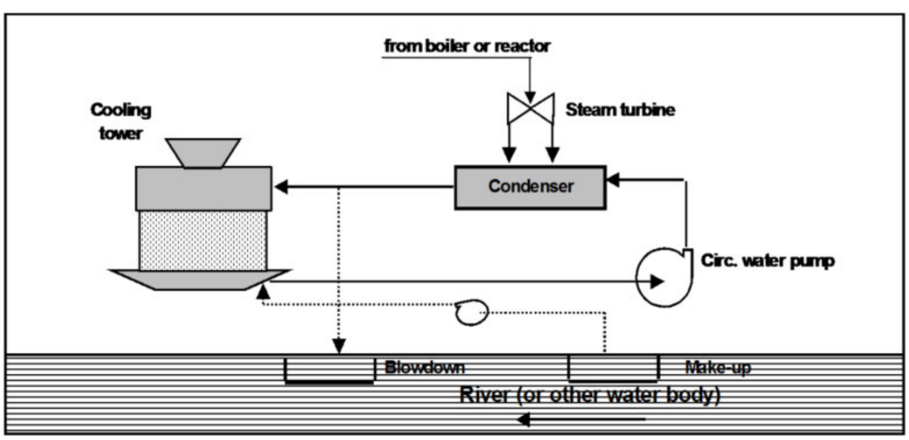

Figure 2. Diagram of the cooling tower as it ties into the rest of the plant

In operation, hot water from the condenser, which carries waste heat from the generating unit, is pumped to the top of the cooling tower. From there, it is distributed across an area known as the “fill,” which is the primary heat transfer medium. The fill is designed to create a large surface area, allowing the water to spread. This design maximizes contact between the water and the airflow moving through the tower, greatly enhancing evaporative cooling efficiency. Mechanical fans draw large volumes of air through the fill and the water, promoting continuous heat and mass transfer. As the air passes through, it absorbs heat and moisture, becoming warmer and more humid before being discharged through the stack at the top of the tower. Once cooled, the water is collected in a basin at the base of the tower and pumped back to the condenser to absorb additional waste heat, completing the cycle. This way, the mechanical draft cooling tower effectively maintains system efficiency by continuously removing waste heat from the power generation process.

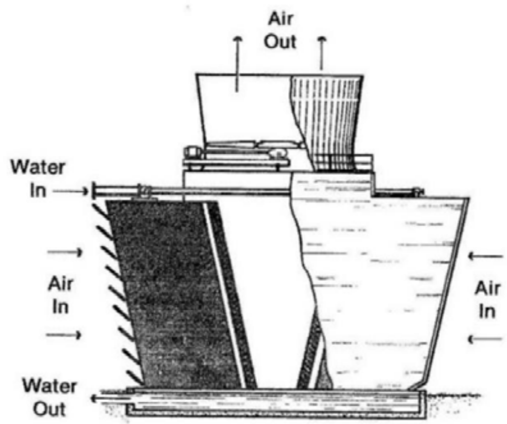

Figure 3. Schematic of a mechanical draft cooling tower

Any power generation facility (e.g., coal, gas, nuclear, biomass) that utilizes a Rankine steam cycle, like the Mitchell Plant, must have a means of condensing steam back into water, which involves transferring a large amount of heat from the steam to another source of water, known as circulating water. The circulating water heats up during the process and must be cooled by discharging it into a large body of water (e.g., a lake, river, or ocean) or a cooling tower. The selection of a cooling tower at the Mitchell Plant minimizes water consumption from the Ohio River and eliminates the need to discharge hot water back into the river, which would potentially have adverse environmental effects.

The new cooling tower will be supplied by a competitively sourced cooling tower industry leader. WPCo has initiated discussions to formalize a contract agreement, which is expected to be completed by Q1 2026. Preliminary specifications for the technology being considered are outlined in the table below.

Design Conditions		Tower Dimensions	
Flow	275,000 gallons per minute (gpm)	Tower Width	78.17 ft
Hot Water	117.5 °F	Tower Length	448.7 ft
Cold Water	91.5 °F	Tower Height	61.58 ft
Wet Bulb	74 °F	Fan Deck Height	47.83 ft

Tower Description		Basin Dimensions	
Model	F674D-20-14	Basin Width	55.5 ft
Number of Cells	14	Basin Length	449 ft
Pump Head	47.41 ft		
Fan Diameter	28 ft		
Motor Size	14 @ 300 Horsepower (Hp)		
Brake Horsepower	14 @ 293.5 Hp		
Evaporation	6,140 gpm		
Drift Rate	0.0010%		

Table 3. Preliminary specifications from a cooling tower industry leader for a mechanical draft cooling tower

Mechanical draft cooling towers are the industry standard for new installations where sufficient water is available to offset evaporation losses—ideal for the Mitchell Plant, which is located along the Ohio River. They are preferred over natural draft towers due to significantly lower capital costs, smaller footprint requirements, and public perception considerations, as natural draft towers are often associated with nuclear facilities. Natural draft towers have not been constructed in the U.S. since the 1980s for these reasons. Additionally, the smaller footprint requirement is a key factor for the Mitchell Plant, given the limited available space on site.

Due to its lower capital cost and sizing advantage, a mechanical draft cooling tower is the most suitable engineering choice for meeting the project's cooling needs.

Organizational Goals

WPCo and AEP are committed to providing reliable, affordable, and environmentally responsible energy to their customers, while adhering strictly to all relevant federal and state energy and environmental regulations. They prioritize modernizing existing infrastructure and integrating advanced technologies to sustain service reliability and manage costs for ratepayers.

The new mechanical draft cooling tower will have an engineered life expectancy of more than 25 years. It will replace the existing hyperbolic cooling tower, which would require significant repairs/upgrades in the near term to allow Mitchell Unit 2 to continue operating, extending its current life by only 10 years. The mechanical draft cooling tower system investment will provide a dependable and efficient cooling solution, supporting plant performance and operational stability. The new tower's projected lifespan of 25+ years will help maintain generation capacity, whether through continued coal combustion or future transitions to alternative or lower-carbon fuels.

Mitchell Plant has consistently demonstrated its commitment to operational excellence and environmental stewardship via significant infrastructure improvements and compliance projects. Notable initiatives include the Coal Combustion Residuals (CCR) and Effluent Limitation

Guidelines (ELG) compliance project, which involved bottom ash conversion, pond closure and repurposing, and flue-gas desulfurization wastewater treatment enhancements.

Through initiatives such as these, WPCo and AEP continue to advance organizational objectives to maintain reliability, minimize environmental impacts, and promote long-term affordability of power generation for customers. The cooling tower upgrade reflects the company's proactive approach, striking a balance between immediate operational needs and long-term energy system resilience and adaptability.

This project also aligns with Governor Morrisey's 25-year energy plan, which prioritizes upgrading existing coal-fired generation to ensure continued delivery of stable, reliable baseload power. By replacing aging infrastructure with a modern mechanical draft cooling tower, the plant will operate more efficiently and economically, supporting the Governor's goal of keeping West Virginia's energy assets online for decades to come.[1] In addition, the project advances the Governor's "Grow West Virginia" economic initiative by ensuring the dependable, affordable power supply needed to attract new businesses and support long-term economic growth across the state.[2]

Economic Competitiveness

A new, modern cooling tower can sustain and potentially improve thermal efficiency, even under suboptimal conditions such as temperature fluctuations and high humidity. By maintaining optimal cooling performance, the new mechanical draft cooling tower will enable more efficient power generation, thereby reducing overall operating costs. Compared to the current natural cooling tower, the new installation is expected to require less maintenance and enable improved operations by using more modern materials, components, and control systems. Investing in a new cooling tower also provides a reliable solution to the existing hyperbolic tower that requires significant repairs and upgrades. This replacement will ensure uninterrupted cooling performance and extend the operational life of the Mitchell Plant, reducing overall costs for AEP and its customers.

Risk Management Plan

The Mitchell Plant project team will implement a comprehensive Risk Management Plan to identify, analyze, monitor, and respond to potential risks throughout the project's lifecycle. The plan will mitigate risks that could impact cost, schedule, technical performance, safety, or regulatory compliance. A Project Risk Register will be established and maintained as a living

[1] Governor Morrisey Provides Details of 25-Year Energy Plan. WV Independent Observer. Sept 11, 2025. https://observerwv.com/governor-morrisey-provides-details-of-25-year-energy-plan/

[2] Governor Patrick Morrisey Announces "Grow West Virginia" Economic Initiative, Makes Targeted Investment in Mettler Packaging to Add 50 New Jobs. West Virginia Office of the Governor. July 10, 2025. https://governor.wv.gov/article/governor-patrick-morrisey-announces-grow-west-virginia-economic-initiative-makes-targeted

document to capture all identified risks, potential impacts, and corresponding mitigation strategies. Each risk will be assessed based on its likelihood of occurrence and the severity of its potential consequences. Risks will be categorized by type—technical, management, schedule, procurement, or financial—and assigned ownership to ensure accountability. The register will also support the development of a risk-based contingency within the project budget. Risks identified as "High" will require a formal written Risk Response Plan, outlining corrective actions, triggers, and mitigation timelines. Initial key risk areas identified in Table 4 include long lead material deliveries, procurement of construction materials, and schedule delays.

Potential Risk	Estimated Probability	Estimated Impact	Mitigation Strategies
Schedule: Potential for schedule delays due to extended permitting, additional engineering requirements, or weather impacts during construction	30%	[redacted]	Implement a detailed project schedule with phase-specific contingency; use a phase-funded approach tied to DOE milestone completion
Procurement and Supply Chain: Potential delays in procurement or delivery of long-lead materials	40%	[redacted]	Prioritize early procurement of critical materials, establish vendor agreements with defined delivery schedules, and maintain buffer inventory where feasible. All materials will be domestically sourced to minimize global supply chain risk
Technical: Potential for unforeseen engineering or integration issues	20%	[redacted]	Conduct comprehensive engineering design reviews and system modeling in Phase 1
Workforce: Availability of skilled construction and technical personnel during peak project phases	15%	[redacted]	Engage early in the RFP process to contract vendors and cross-train internal staff as needed

Table 4. Initial identification of potential risks (Class V estimates)

Control Number: 3605-1510

[redacted]

SUMMARY

Project Management Professional (PMP) with 9+ years of experience in Coal-Fired Power Plants, Distribution, Transmission, Right of Way, and Electrical/Lighting Wholesale. My skills include leadership, planning, executing, scheduling, risk management, and communication. I am seeking to use my work experience, skills, and education to help organizations with their ongoing projects. In my current and previous roles, I have led several multimillion-dollar projects and programs that continue to positively impact AEP's customers.

PROFESSIONAL EXPERIENCE

American Electric Power – Senior Project Manager (ERCOT & APCo) – Generation & Distribution
(November 2022 – present)
Columbus, Ohio

- Managing a first of a kind generator project in order to increase maximum capacity for station needs offsite
- Managing multiple projects within a matrix team environment at Mitchell Power Plant and in ERCOT Distribution
- Providing leadership, direction, and effective communication to initiate, plan, execute, monitor and control, and close projects in a safe, efficient, economical, risk-balanced approach to achieve short and long range goals and to obtain maximum customer satisfaction
- Developing relationships and effectively communicate with all stakeholders including internal customers, external customers, team members, suppliers, contractors, and vendors. This includes groups within AEP Transmission, Distribution, and Generation
- Creating and managing the yearly schedule and cost baselines for projects
- Planning, organizing, directing, coordinating and supervising project activities
- Managing, developing, reviewing and coordinating the project plan, schedule, and budget
- Managing cost and providing timely reallocation of funding as needed
- Leading meetings and providing project updates including stakeholder presentations
- Providing clear and concise monthly reporting on projects up to the SVP level
- Actively managing working relationships with the project team, customers, contractors, vendors, and suppliers
- Providing specific guidance to reduce risk and to improve the project schedule and costs
- Reviewing and approving deliverables to ensure projects are on time and in budget
- Ensuring maximum customer satisfaction and demonstrating effective performance of project work activities
- Supporting and hold employees and contractors accountable for the AEP System Safety Process, ensuring a safe working environment focused on Zero Harm

American Electric Power – Project Manager (I&M) – Transmission Development & Right of Way (December 2019 – November 2022)
New Albany, Ohio

- Ensured that Transmission projects were properly developed to hand-off to the project execution team
- Directed planning meetings and project updates with supportive role in stakeholder presentations
- Developed working relationships with the project team, contractors, vendors, and suppliers
- Provided guidance, instruction, and training to improve design, systems, procedures, schedules, and costs
- Managed the project team in ensuring effective and timely performance and deadlines of project activities
- Assigned as the Right of Way Telecom Lead that tracked permitting for construction on projects
- Led bi-weekly project calls with the project team and vendors
- Prepared and presented right of way kick-off meetings to begin acquisition activities
- Mentored and trained new team members on AEP right of way processes and the project lifecycle
- Reviewed monthly forecasting on assigned capital projects

- Handled negotiations with landowners for the acquisition of land rights
- Settled damage claims with property owners relative to property damage
- Reviewed and interpreted legal documents, surveys, legal descriptions, appraisals, and reports
- Prepared approved legal documents for the acquisition of land rights
- Provided support to other AEP Business Units in regard to questions and procedures in the acquisition of land rights
- Maintained property owner files, maps, drawings, exhibits and detailed progress reports
- Completed estimates & scopes for projects, and managed, developed, and reviewed deliverables from vendors
- Monitored the closeout process and establish any lessons learned for future improvements

Loeb Electric – Project Coordinator – North America Accounts (January 2018 – December 2019)
Columbus, Ohio

- Project scopes included internal and external store lighting retrofits for Walmart, L-Brands, and Meijer
- Processed and performed take-offs with electrical materials that were needed for the desired projects
- Helped create logistical routes across North America to complete jobs by their deadlines
- Created purchase orders and work orders for future jobs
- Presented monthly project updates to the organization's executives
- Provided overall project support for assigned projects for designated Project Manager
- Took and maintained ownership of assigned queues and projects
- Processed material orders for assigned projects and queues
- Completed calls for scheduling, quality, waste pickup, and security to our company's accounts

Loeb Electric – Project Services Specialist – National Accounts (May 2016 – January 2018)
Columbus, Ohio

- Managed accounts throughout North America with stores that requested electrical work
- Built relationships with account managers and technicians
- Made phone calls and emailed regularly to receive updates on current jobs
- Conducted a time study analysis for dispatchers and service coordinators
- Designed a training manual for newly hired service coordinators
- Prepared standard operating procedures for service coordinators daily work
- Worked on different processes within accounts payable and accounts receivable

EDUCATION & CERTIFICATIONS

Franklin University **Master of Business Administration (MBA)**
Project Management Institute **Project Management Professional (PMP)**
Otterbein University **Bachelor of Business Administration (BBA)**
OSHA 30 Outreach Training Program **Construction Safety Certified (DOL card)**

ORGANIZATIONS, GROUPS, & ACCOMPLISHMENTS

Member of the Project Management Institute (PMI)
Member of the International Right of Way Association (IRWA)
AEP 2025 Corporate DEI Liaison for 1RP
Chair of AEP's 2024 Project Solutions DEI Committee
Awardee of AEP's 2023 Project Solutions Community Engagement Award
Member of AEP's 2023-2025 Generation Goldfish Program
Member of AEP's 2023-2025 Project Solutions Mentoring Program
Member of AEP's 2023-2024 Distribution Culture Action Plan Team
Member of AEP's 2022 Transmission SOAR Culture Team (Siting, Outreach, and Right of Way) Member of AEP's 2021 Grid Development Strategic Goal for Diversity & Inclusion Group Member of AEP's 2020 Transmission Safety Group
Graduate of AEP's 2020 Transmission Talent Onboarding Program

[redacted]

Summary

Recognized for establishing, managing, and motivating high-performance teams—practices honed through a commitment to introducing new standards, establishing operational best practices, improving quality, and increasing enterprise value.

Employment

2023-Present — Managing Director, Federal Grants and Broadband

- Tasked with finding, analyzing, seeking alignment, and implementation of federal grant applications and compliance to help keep customer cost impacts low through the acquisition of federal grant funds
- Responsible for seizing opportunities to maximize federal funding within our footprint through grant development utilizing a comprehensive fiber strategy that helps us modernize the electric grid while connecting areas without broadband coverage
- Company's subject matter expert and witness for regulatory proceedings for grid modernization, federal grant and rural broadband pursuits with an associated track record of success

2021-2023 — Director, Broadband and Telecom Business Development

- Responsible for uncovering and extracting additional annual revenue from leveraging existing unutilized dark fiber and Vertical assets
- Tasked with implementation of marketing partners to drive additional revenue from leveraging existing unutilized telecom, transmission, and real estate assets
- Responsible for seizing opportunities to maximize federal funding within our footprint through grant development utilizing a comprehensive fiber strategy that helps us modernize the electric grid while connecting areas without broadband coverage

2016-2021 — Director, GRID Modernization

- Responsible for AEP Ohio's new grid technology including its gridSMART Phase 2 Deployment - $385M capital.
- Regulatory and Filing Leader of AEP Ohio's support of the Smart City / Smart Columbus Project including the proposed AEP Ohio deployment of Smart Lighting, Microgrid and Battery Storage, and Electric Vehicle Charging Infrastructure - $87M capital.
- Responsible for AEP Ohio's Risk Management organization and activities.

Education

1999-2003 — BA, Business Administration, Mount Vernon Nazarene University

Control Number: 3605-1510

[redacted]

[redacted]

Summary

Results-driven maintenance and engineering professional with extensive experience in the utility sector, currently serving as a Maintenance Superintendent Sr. Proven ability to lead and mentor teams while developing and implementing strategies to enhance equipment reliability and performance. Expertise in outage planning and execution, ensuring compliance with safety and regulatory standards. Demonstrated success in project management of multi-discipline engineering projects, conducting audits, and providing training on new technologies. Holds a Bachelor of Science in Electrical and Computer Engineering from The Ohio State University, combining technical knowledge with strong leadership skills to drive operational excellence and cost efficiency.

PROFESSIONAL EXPERIENCE

AMERICAN ELECTRIC POWER, Moundsville, WV
2024 - Present
Maintenance Superintendent Sr

- Supervise and mentor electrical and mechanical maintenance staff, providing guidance and training as needed.
- Develop and implement maintenance strategies to optimize equipment reliability and performance.
- Oversee preventive and corrective maintenance activities, ensuring timely completion of work orders.
- Manage administrative staff, budgets, and resources, tracking expenses and identifying cost-saving opportunities.
- Collaborate with engineering and operations teams to identify maintenance needs and improvements.
- Ensure compliance with all safety programs and regulatory requirements.
- Maintain accurate records of maintenance activities and equipment performance.
- Analyze maintenance data to identify trends and recommend improvements.

AMERICAN ELECTRIC POWER, Moundsville, WV
2023 - 2024
Outage Process Owner

- Responsible for planning and execution of scheduled and/or forced outages, including plant work, RSO, and contract labor work, and coordinating outage activities and operations.
- Establish outage critical path, outage duration, and work schedules.
- Establish work scopes based on previous outage inspection reports, predictive maintenance, preventative maintenance, circular letters, lessons learned, facility health reports, long-range planning, and NDE test results.

- Provide regular updates and reports on work progress, safety performance, schedule adherence, and budget performance.
- Supervise Outage Coordinators in the planning and execution of outage plans.

AMERICAN ELECTRIC POWER, Moundsville, WV
2021 - 2023
Electrical Process Owner

- Responsible for the overall operations and maintenance of electrical process turbine-generator, transformer, and BOP equipment.
- Develop multi-year plans and budgets to ensure Circular Letter compliance.
- Ensure generator-to-line NERC compliance.
- Responsible for outage plans and schedules.
- Responsible for personnel safety on all electrical process equipment.

AMERICAN ELECTRIC POWER, Moundsville, WV
2016 - 2021
Supervising Engineer (2019-2021), Regional Engineer (2016-2019)

- Supervise engineering resources to perform multi-discipline projects utilizing EWC.
- Project manager of DCS/PLC controls upgrades, GSU replacements, and process upgrades, ensuring projects are completed on time, on budget, and without impacting plant operations.
- Perform safety-in-design checks and peer reviews of new installations.
- Provide guidance to Engineers and I&C supervisors to ensure hardware and software maintenance and upgrades are performed as needed.
- Provide training and documentation to energy production personnel on the operation of all new equipment.
- Perform NERC audits to ensure compliance.

EDUCATION

Bachelor of Science in Electrical and Computer Engineering
THE OHIO STATE UNIVERSITY
Columbus, OH May 2016

Qualification

Current U.S. Citizen

ADDITIONAL TRAINING

- API 579-1/ASME FFS-1 Fitness for Service Training.
- SEL protection relay and automation.
- CISCO Networking.
- P6 Professional Scheduling

Control Number: 3605-1510

[redacted]

PROFESSIONAL PROFILE

A hardworking and dedicated individual who is well-organized with an exceptional focus on safety and culture. An exceptional leader in the Supply Chain/Accounting organization. I work diligently to establish relationships across cross-functional teams, enabling us to achieve our goals and fulfill our daily work duties successfully. I am a highly skilled supervisor in receiving, inventory management, invoicing, and catalog management. With this experience, it has developed strong interpersonal and communication skills, and I have become an exceptional trainer. I work very hard alongside my team and colleagues to ensure that they are aware of breakthrough objectives and that we meet or exceed them.

PROFESSIONAL EXPERIENCE

Cabela's Distribution Center

Receiving Coordinator 2004-2008

- Managed day and night shift receiving and shipping, consisting of over 50 employees.
- Maintained and manage budgeted costs within that department.
- Maintained headcount for the department and future needs (ex. during holidays we would have the need to employ temporary employees)
- Fork truck, stacker, long tail, and bobtail trainer.
- Worked closely with human resources department to hire associates that would be the proper fit for the positions that we had open and scheduled interviews.
- Operated training classes held to keep up with the OSHA standard for the entire warehouse. Our safety record was exceptional, considering we were in the construction phase of the center.
- Moved across departments to broaden my understanding of distribution processes.

American Electric Power

Stores Attendant 2008-2010

- Carried out the day-to-day functions of a storeroom attendant.

Stores Attendant Senior 2010-2013

- Day-to-day responsibilities of a senior storeroom attendant.
- Worked closely with the catalog department and the vendors to complete the u-3 FGD parts setup.
- Managed the project to complete re-organization of the open stock area at each of the outer warehouses.
- Daily duties included work with the plant to acquire material/get quotes/set up delivery/plan the outage material needed, etc.

Kentucky Power Co Mitchell Plant Stores, Moundsville, WV

NE Storeroom Supervisor 2013-2021

- Supervised attendants to service business partners during times that we are really needed and assigned work as necessary.
- Participate in lean events, a trainer for the MAXIMO implementation, a trainer for HPI Tools and concepts for the 2021 HPI initiative, participating in the CORE visit assessment standardization assessment.
- Meet and exceed KPI's that are attainable.
- Safety focus with over an 11-year incident-free record.
- Administer PAT test for new employees and other storerooms on the East Coast.
- Maintain stock and work closely with our suppliers.

Regional Supply Chain Supervisor 2021-2025

- Oversight of multiple facilities in the Northeastern area.
- Cascaded tasks, budgets, and duties down to employees at the facility.
- Communicated information to employees pertaining to invoicing, procuring, transportation, cataloging, and many other areas of operation within the company.
- Hired and trained staff.
- Set performance goals while collaborating with upper management to secure the goals that align with the company.
- Site visits to assess compliance, address questions, and support the local team.

Administrative Supervisor Senior 2025-Present

- Monitored and worked to maintain the budget for Mitchell plant.
- Guide both the storeroom and the accounting department to make sure that we remain in SOX compliance in invoicing, payroll, purchase order, storage, and work orders.
- Working to achieve clear guidelines and expectations within both departments.

EDUCATION

West Liberty University, West Liberty, WV
Bachelor of Science
Business Administration, with specialization in Computer Information Systems

ADDITIONAL SKILLS

- PAT (physical ability test) administrator
- LEAN green belt – lean administrator
- Certified fork truck trainer
- Certified MAXIMO trainer
- Proficient in Microsoft – WORD, EXCEL, POWERPOINT, LOTUS NOTES, OUTLOOK
- Proficient in PeopleSoft expense
- Proficient in Asset Suite
- Proficient in Maximo
- PASS fuel delivery certification
- Exceptional driving record
- HPI trainer
- OSHA 30 certification
- SMITH SYSTEM driving certification

Control Number: 3605-1510

[redacted]

Experience:

FGD Process Supervisor SR 2025-Present

- Manage, plan, and direct process maintenance for FGD
- Develop short- and long-range plans based on equipment run time and circular letter compliance
- Develop, update, and maintain 10-year projected budget.
- Oversee a 20-person team of exempt and hourly employees.

Maintenance Supervisor SR. 2021-2025

- Supervise the work of other employees in executing plant maintenance responsibilities to achieve efficient, safe, and reliable operation of plant equipment.
- Maintain and ensure safe working conditions.
- Supervise, coordinate, plan direct, and/or organize plant maintenance activities.
- Coordinate the planning for maintenance support for plant outages. Develop workflow charts and critical paths, analyzing and overseeing requisitioning of material and equipment needs.

Planner Prin. Mitchell Power Plant, 2017- 2021

- Daily and outage maintenance planner
- Schedule and plan crews for the upkeep of facility
- Utilize Maximo and PASTA work management systems.
- Work with ICE and Operations to schedule equipment for servicing.
- Solicit quotes and procure various parts and equipment.
- Fill in for crew and Maintenance Supervisor SR. as needed.

Planner SR. RSO zone 3, 2016-2017

- Daily and outage maintenance planner
- Scheduled and planned crews for the upkeep of facilities
- Worked between Cardinal, Mitchell, and Dresden plants for planning purposes.
- Filled in as crew supervisor as needed.

Turbine Mechanic SR. AEP RSO zone 3, 2006-2016

- Performed daily and outage tasks for Northern and Southern regions of AEP.
- Repaired/Rebuilt coal and gas-powered steam turbines and generators.
- Performed preventative and corrective maintenance as directed.

Education:

United States Air Force
- 504 hours of on-the-job training Sheppard AFB Texas
- Airman Leadership School
- Air Force Trainers Course
- Maintenance Qualification Training
- Flight line Engine Operation
- Aircraft Advanced Troubleshooting
- Multipoint Refueling Systems
- Certified Physical Training Leader

Belmont Technical College
- Welding and Fabrication
- Completed 51 credit hours in Oxyacetylene, Shielded Arc, MIG, and TIG welding.
- Weld testing, Welding problems and solutions, and welding fabrication

Training:

- Weld Checker, Red Dye
- Power Up & Lead
- Front Line Leadership training
- OSHA 30hr training
- Root Cause Analysis (LCA- Failsafe)
- JSA/JHA courses
- HPI Tool Training
- Clearance Permit System Training & Annual Refreshers
- Excavation Safety for Competent Person

Current U.S. Citizen

Control Number: 3605-1510

[redacted]

EDUCATION

2001-2005 Marshall University
Lewis College of Business
Graduated May of 2005
Bachelor's Degree in Accounting
Minors: History and Economics

EMPLOYMENT

Jan 2024 - Present Plant Manager - Mitchell Plant
Job Description: Focusing on achieving Zero Harm through utilization of HPI tools, Staffing/Resource Management, Business Plans, Oversee all aspects of the business site finances, Operation of the facility via Operations, Material Handling and the Lab, & Site Maintenance Program. Promote a Continuous Improvement program.

Jan 2018 - June 2021 Energy Production Supt Sr - Mitchell Plant
Job Description: Focusing on achieving Zero Harm through utilization of HPI tools, Staffing/Resource Management, Business Plans, Oversee Operation of the facility via Operations, Material Handling and the Lab, Plant Health Report, HR/Labor Relation/Union Grievances/Messages, PMRs/ Developmental Plans for direct & indirect reports, Promote Lean & Achieving Excellence & much more

Jan 2018 - Dec 2019 Maintenance Supervisor - John Amos Plant
Job Description: Focusing on achieving Zero Harm, implementing lean ideas, completing Gap Action Plans, controlling the facility budget, reviewing emergent work, PM compliance & schedule compliance.

Feb 2017 - Jan 2018 Maintenance Supervisor (Outage Coordinator FO/SO) – John Amos Plant
Job Description: coordinating work with contractors and plant maintenance, helped to create Operations Outage Priority sheet which is now a key focus in our outage efforts, performing planning/travelers for Forced and scheduled outage, getting directly involved in our Long Range Plan, working with the scheduler to improve our pre-fabricating process for our outages which has led to availability for work scope increase during the outages. Developing a new Plant Health Report

Jul 2015 - Jan 2017 Maintenance Supervisor – John Amos Plant
Job Description: Completed CI upgrade project on AOD/Urea systems - installed all new valves, piping, etc, Upgraded Urea System to improve pump efficiencies, installed new strainers to prevent pump failures, focused on improving leaks, ventilation, etc to allow building entry without respirators, implemented Intent Based Leadership at John Amos, focused on Unit 3 steam process planning and forced outage work planning/coordination

Jan 2015 - July 2015 Plant System Owner I (Operations Supervisor) - Big Sandy Plant AEP
Job Description: Check completion of routine operator rounds, job briefs, crew time entry, work requests, assist with clearance system and perform safety meetings/implement HPI tools

Jan 2014 - Dec 2014 Plant System Owner I (Maintenance Supervisor) - Big Sandy Plant AEP
Job Description: Run Maintenance Crew, Identify weekly work plans, Clearance Request/Discussions, Review pertinent JHAs/SIBs, Job Briefs, Implement HPI Tools, Work Requests, & Delivered all Corporate messages/initiatives directly to crew.

Jan 2013 - Dec 2013 Plant System Owner I (Coal Yard Evening Shift Supervisor) - Big Sandy Plant AEP
Job Description: Control Fuels Budget, CY Outages, Job Briefs, Implement HPI Tools, Checking Equipment, Work Requests, CY Clearances & Organize Contract Labor

Oct 2012-Dec 2012 Labor Gang Supervisor- Big Sandy Plant AEP
Job Description: Manpower contract labor crew - housekeeping, combustible dust cleaning, i.e., using a vacuum truck in the unit, washing coal conveyors & outage cleaning

2010-2012 Administrative Supervisor- Big Sandy Plant AEP
Job Description: Budgeting, front-line leadership of the plant accounting department, housekeeping, & LITA (IT Rep)

2008-2010 Administrator III – Kanawha River Plant- AEP
Job Description: Budgeting, LITA representative, NERC Lead, capital work orders, security, assist/direct admin department, housekeeping & materials coordinator

2005-2008 Administrative Associate - Kanawha River Plant- AEP
Job Description: Process invoices, contracts, coal entry/pricing & ash entry/billing

Training:

- Generation Targeted Leadership Development Program 2015
- HPI Tool Training
- Clearance Permit System Training & Annual Refreshers
- JSA/JHA courses
- NERC CIP training
- Root Cause Analysis (LCA- Failsafe)
- Business Financial Accounting Online Training- AEP Specific
- OSHA 30hr training
- Front Line Leadership training-
- Power Up & Lead
- Business/Technical Writing Course
- Business Objects/Cognos Training
- Scaffold Competency
- Vibration Analysis
- Oil Analysis
- Weld Checker
- Red Dye (2)
- Weld Checker Planner (2)
- Intent Based Leadership Plant Facilitator

Control Number: 3605-1510

[redacted]

WORK EXPERIENCE
American Electric Power, Columbus, Ohio | April 2011 - Present
Director – Civil Engineering | Dec 2024 - Present

- Lead technical team of Civil, Structural and Geotechnical engineers supporting both existing and new generating facilities.

Director / Manager – New Generation & Project Engineering | Aug 2019 - Dec 2024

- Led multidisciplinary teams in the development and execution of Wind, Solar, Battery, and Gas generation projects.
- Directed bid strategy and self-development processes to deliver competitive proposals for new generation initiatives.
- Oversaw procurement and engineering design for gas turbine equipment and plant siting studies.
- Collaborated with internal and external stakeholders to align generation deployment strategies and execution plans.
- Presented project outcomes to executive leadership and advanced Shared Services strategy for major initiatives.
- Mentored engineering staff and drove organizational culture initiatives to enhance team performance and engagement

Supervisor / Engineer, Civil Engineering | April 2011 - Aug 2019

- Supported Civil Engineering projects at existing power plants.
- Managed capital and retirement projects at existing power plants, including ELG retrofits and CCR closures.
- Led engineering efforts for hydro facilities and wind repower projects
- Developed and oversaw environmental and Dam Safety compliance programs (CCR & ELG).
- Conducted risk assessments for coal ash and cooling lake infrastructure.
- Contributed to O&M strategy development for renewable assets within cross-functional teams.

EMH&T Inc, Columbus, Ohio | April 2004 - April 2011
Design Engineer

- Performed engineering and led team for large utility, industrial, municipal, and commercial projects

LICENSURE & CERTIFICATIONS

- Registered Professional Engineer in the State of Ohio since 2008

EDUCATION

The Ohio State University, Columbus, Ohio

B.S. Civil Engineering, June 2003

Control Number: 3605-1510

[redacted]

CAREER SUMMARY	Continue building trusting relationships with various organizations throughout AEP, while utilizing my leadership, knowledge, and abilities to successfully and safely complete projects.	
CERTIFICATIONS, TRAINING & EDUCATION	• OSHA 510 and 500 • Certified Rigging Instructor • Over 60 Welding Certifications from SMAW-GTAW • 2000 Graduate Apprentice	
SKILLS	• Can manage multiple projects simultaneously, meeting schedule dates and customer expectations • Building a teamwork atmosphere with all parties involved in project processes	• Time management • Proficient in multiple AEP programs/software
WORK HISTORY	**SITE CONSTRUCTION MANAGER – AEP SS CONSTRUCTION SVCS** 07/2024 – Present Responsible for the management, coordination, and supervision of one or more AEP construction projects. Direct and administer the planning, scheduling, QA/QC, contract administration, coordination, and supervision of all construction work activities in a safe, efficient, and economical manner. Provide leadership, communication, and develop partnerships with internal (plant management teams) and external customers, labor contractors, suppliers, vendors, and governmental agencies • Mitchell Cooling Tower Shell Reinforcement • Mitchell Haul Road • Mitchell Waste Water Treatment Facility **CONSTRUCTION COORDINATOR SR – AEP PS CONSTRUCTION SVCS** 06/2017 – 07/2024 Coordinate assigned construction projects located in AEP service territory. Participate in planning, scheduling, and coordination of all construction work activities in a safe, efficient, and economical manner. Collaborate with Plant management teams and external customers, labor, contractors, suppliers, vendors, and governmental agencies. • Amos CCR/ELG • Rockport DSI • Amos U3 Air Heater Upgrades • Wilkes Reheat/Superheat/Outlet Header Change Out • Welsh Rail Car Dumper Replacement • Welsh U2 Precipitator Demo • Welsh Pulse Jet Fabric Filter	

Control Number: 3605-1510

[redacted]

Leadership

29+ years of Power Generation Industry experience; 15+ years in a leadership role with responsibility for overseeing and directing the activities of facility employees and contractors in a safe, compliant, reliable, and economical manner, including electric power production, maintenance, engineering, construction, accounting, procurement, materials management, human resources, public affairs, and compliance with regulating agencies. This responsibility also includes developing strategic and tactical plans to ensure that performance and budget are aligned with asset management expectations. Additionally, establishing and maintaining two-way communication with employees, managers, and the public, as well as providing leadership and managing change through the development of a culture that promotes/supports teamwork, process improvement activities, employee development, and proper recognition and reward.

Experience

01/2024 – Present
VP Generation Assets • Appalachian Power Company • Charleston, WV

04/2022 – 01/2024
Managing Director Generation & Indiana & Michigan Power, Kentucky Power • Rockport, IN

12/2020 – 04/2022
Plant Manager Rockport Plant • AEP • Rockport, IN

05/2018– 12/12/20
Plant Manager Clinch River • AEP • Cleveland, VA

01/2017– 05/2018
Plant Manager – Gavin Plant • Lightstone Generation LLC • Gallipolis, OH

08/2015 – 01/2017
Plant Manager – Gavin Plant • AEP • Gallipolis, OH

05/2011 – 08/2015
Facility Manager – Waterford & Wind Generation • AEP • Waterford, OH / Abilene, TX / Iraan, TX

08/1996 – 05/2011
Various roles – Clinch River & Sporn • AEP • Cleveland, VA / New Haven, WV

Education

Bachelor of Science, Mechanical Engineering / Virginia Tech, Blacksburg, VA

Control Number: 3605-1510

[redacted]

My goal is to steadily obtain more challenging and fulfilling roles that utilize my strong analytical skills and ability to improve the performance of those around me.

EXPERIENCE

2022 - PRESENT
BUDGET ANALYST STAFF, AEP – APPALACHIAN POWER BUSINESS OPERATIONS
Manage operations and maintenance (O&M) budgets and Capital budgets for Appalachian Power (APCo), Wheeling Power, and Kentucky Power generating assets which total $300M annually and include jointly owned facilities and facilities with concurrent cost recovery requiring special handling. Provide Generation data and help build testimony for base rate cases, various filings, and discovery questions. Data includes, but not limited to: O&M expenses, fuel costs, capital expenditures, plant in service activity, and operational data. Coordinate with Regulatory team and witnesses to ensure data is telling the same story as the associated testimony. Build, schedule, and maintain Cognos reports, often joining many different data sources, for users throughout AEP.

2021- 2022
BUDGET ANALYST SENIOR, AEP – APPALACHIAN POWER BUSINESS OPERATIONS
Assisted budgeting O&M and Capital for APCo Distribution and aligned Distribution's project work plan with the budget. Provided Distribution data for various filings and discovery questions. Created, managed, and closed major storm and mutual assistance work orders.

2019 - 2021
ADMINISTRATIVE SUPV, AEP - MITCHELL PLANT
Managed the accounting operations at the Mitchell Plant, which included budgeting, variance reporting, invoice processing, contract requisitions, capital work order processing, Sarbanes-Oxley compliance, document retention, ad-hoc reporting, and managing direct reports. Self-taught Cognos and supported the eastern Generation fleet by creating dozens of Cognos reports for various business needs and facilitated several group and one-on-one Cognos training sessions via WebEx.

2018 - 2019
ADMINISTRATIVE SUPT/ACCOUNTING AND BUSINESS SYSTEM PROCESS OWNER,
CARDINAL OPERATING COMPANY - CARDINAL PLANT

Successfully managed the transition of the accounting, procurement, and inventory management functions from AEP to Buckeye Power in March 2018. Owned the Asset Suite application and integrations with other systems (ComTrac, Dynamics GP, Oracle, and ADP), developed numerous new work processes, and worked with ABB to develop Power BI reporting cubes and subsequent reports on Asset Suite data.

2013 - 2018

ADMINISTRATIVE SUPV/SUPT, AEP/AEP GENERATION RESOURCES - CARDINAL PLANT

Managed the accounting operations at the Cardinal Plant, which included budgeting and variance reporting separately for each owner, invoice processing, contracting, capital work order processing, Sarbanes-Oxley compliance, document retention, ad-hoc reporting, and managing direct reports. Completed Generation Resource's leadership development program, attended Lean Green Belt training facilitated by Bescorp, and facilitated the financial module for Front Line Leader Training several times.

2007 - 2013

COAL EQUIPMENT OPERATOR, AEP - CARDINAL PLANT

Safely operated heavy equipment and conveyor belts to reclaim, stockpile, and load out coal, limestone, and gypsum. Facilitated aerial lift training and served as step up supervisor. Installed water lines along coal conveyors for cleaning and executed other process improvement ideas.

EDUCATION

2005

B.A. MATHEMATICS AND ECONOMICS, OHIO UNIVERSITY

4.0 GPA, Summa Cum Laude, Phi Beta Kappa member

2001

HIGH SCHOOL DIPLOMA, BUCKEYE LOCAL HIGH SCHOOL

4.0 GPA, Valedictorian, 2-time National Spelling Bee participant

SKILLS

- Strong analytical skills
- Excellent coach and mentor
- Self-motivated
- Cognos, Power BI, and Business Objects
- Asset Suite, Maximo, and Storms
- Ability to quickly learn new processes
- Synthesizing process improvement ideas
- Constant pursuit of excellence
- Microsoft Office suite
- PeopleSoft, ComTrac, PowerPlan, MSC

OMB Number: 4040-0004
Expiration Date: 11/30/2025

Application for Federal Assistance SF-424

* 1. Type of Submission:
  - [x] Preapplication
  - [ ] Application
  - [ ] Changed/Corrected Application

* 2. Type of Application:
  - [x] New
  - [ ] Continuation
  - [ ] Revision

* If Revision, select appropriate letter(s):

* Other (Specify):

* 3. Date Received: 11/21/2025

4. Applicant Identifier:

5a. Federal Entity Identifier:

5b. Federal Award Identifier:

State Use Only:

6. Date Received by State:

7. State Application Identifier:

8. APPLICANT INFORMATION:

* a. Legal Name: Wheeling Power Company

* b. Employer/Taxpayer Identification Number (EIN/TIN): [redacted]

* c. UEI: PXY1JRBLEJV9

d. Address:

* Street1: 1 Riverside Plaza

Street2:

* City: Columbus

County/Parish:

* State: OH: Ohio

Province:

* Country: USA: UNITED STATES

* Zip / Postal Code: 43215-2373

e. Organizational Unit:

Department Name:

Division Name:

f. Name and contact information of person to be contacted on matters involving this application:

Prefix:

* First Name: Scott

Middle Name:

* Last Name: Osterholt

Suffix:

Title: Managing Director Federal Grants & Broadband

Organizational Affiliation: American Electric Power (AEP)

* Telephone Number: [redacted]

Fax Number:

* Email: s[redacted]

Application for Federal Assistance SF-424

*** 9. Type of Applicant 1: Select Applicant Type:**

Q: For-Profit Organization (Other than Small Business)

Type of Applicant 2: Select Applicant Type:

Type of Applicant 3: Select Applicant Type:

* Other (specify):

*** 10. Name of Federal Agency:**

DOE

11. Assistance Listing Number:

81.255

Assistance Listing Title:

Clean Energy Demonstrations

*** 12. Funding Opportunity Number:**

DE-FOA-0003605

* Title:

Restoring Reliability: Coal Recommissioning and Modernization

13. Competition Identification Number:

Title:

14. Areas Affected by Project (Cities, Counties, States, etc.):

Add Attachment | Delete Attachment | View Attachment

*** 15. Descriptive Title of Applicant's Project:**

Mitchell Mechanical Draft Cooling Tower Modernization Project

Attach supporting documents as specified in agency instructions.

Add Attachments | Delete Attachments | View Attachments

Application for Federal Assistance SF-424

16. Congressional Districts Of:

* a. Applicant: OH-015
* b. Program/Project: WV-002

Attach an additional list of Program/Project Congressional Districts if needed.

[ ] Add Attachment | Delete Attachment | View Attachment

17. Proposed Project:

* a. Start Date: 06/01/2026
* b. End Date: 09/29/2028

18. Estimated Funding ($):

* a. Federal	[redacted]
* b. Applicant	[redacted]
* c. State	0.00
* d. Local	0.00
* e. Other	0.00
* f. Program Income	0.00
* g. TOTAL	[redacted]

*** 19. Is Application Subject to Review By State Under Executive Order 12372 Process?**

☐ a. This application was made available to the State under the Executive Order 12372 Process for review on ______.

☐ b. Program is subject to E.O. 12372 but has not been selected by the State for review.

☒ c. Program is not covered by E.O. 12372.

*** 20. Is the Applicant Delinquent On Any Federal Debt? (If "Yes," provide explanation in attachment.)**

☐ Yes ☒ No

If "Yes", provide explanation and attach

Add Attachment | Delete Attachment | View Attachment

21. *By signing this application, I certify (1) to the statements contained in the list of certifications and (2) that the statements herein are true, complete and accurate to the best of my knowledge. I also provide the required assurances** and agree to comply with any resulting terms if I accept an award. I am aware that any false, fictitious, or fraudulent statements or claims may subject me to criminal, civil, or administrative penalties. (U.S. Code, Title 18, Section 1001)**

☒ ** I AGREE

** The list of certifications and assurances, or an internet site where you may obtain this list, is contained in the announcement or agency specific instructions.

Authorized Representative:

Prefix:
* First Name: Scott
Middle Name:
* Last Name: Osterholt
Suffix:

* Title: Managing Director Federal Grants & Broadband

* Telephone Number: [redacted]
Fax Number:

* Email: s[redacted]

* Signature of Authorized Representative: Scott Osterholt
* Date Signed: 11/10/2025

View Burden Statement

OMB Number: 4040-0004
Expiration Date: 11/30/2025

Application for Federal Assistance SF-424

* 1. Type of Submission:	* 2. Type of Application:	* If Revision, select appropriate letter(s):
☒ Preapplication	☒ New	
☐ Application	☐ Continuation	* Other (Specify):
☐ Changed/Corrected Application	☐ Revision	

* 3. Date Received:	4. Applicant Identifier:
11/21/2025	

5a. Federal Entity Identifier:	5b. Federal Award Identifier:

State Use Only:

6. Date Received by State:		7. State Application Identifier:	

8. APPLICANT INFORMATION:

* a. Legal Name:	Wheeling Power Company
* b. Employer/Taxpayer Identification Number (EIN/TIN):	[redacted]
* c. UEI:	PXY1JRBLEJV9

d. Address:

* Street1:	1 Riverside Plaza
Street2:	
* City:	Columbus
County/Parish:	
* State:	OH: Ohio
Province:	
* Country:	USA: UNITED STATES
* Zip / Postal Code:	43215-2373

e. Organizational Unit:

Department Name:	Division Name:

f. Name and contact information of person to be contacted on matters involving this application:

Prefix:	
* First Name:	Scott
Middle Name:	
* Last Name:	Osterholt
Suffix:	
Title:	Managing Director Federal Grants & Broadband
Organizational Affiliation:	American Electric Power (AEP)
* Telephone Number:	[redacted]
Fax Number:	
* Email:	[redacted]

Application for Federal Assistance SF-424

*** 9. Type of Applicant 1: Select Applicant Type:**

Q: For-Profit Organization (Other than Small Business)

Type of Applicant 2: Select Applicant Type:

Type of Applicant 3: Select Applicant Type:

* Other (specify):

*** 10. Name of Federal Agency:**

DOE

11. Assistance Listing Number:

81.255

Assistance Listing Title:

Clean Energy Demonstrations

*** 12. Funding Opportunity Number:**

DE-FOA-0003605

* Title:

Restoring Reliability: Coal Recommissioning and Modernization

13. Competition Identification Number:

Title:

14. Areas Affected by Project (Cities, Counties, States, etc.):

Add Attachment | Delete Attachment | View Attachment

*** 15. Descriptive Title of Applicant's Project:**

Mitchell Mechanical Draft Cooling Tower Modernization Project

Attach supporting documents as specified in agency instructions.

Add Attachments | Delete Attachments | View Attachments

Application for Federal Assistance SF-424

16. Congressional Districts Of:

* a. Applicant: OH-015 * b. Program/Project: WV-002

Attach an additional list of Program/Project Congressional Districts if needed.

Add Attachment | Delete Attachment | View Attachment

17. Proposed Project:

* a. Start Date: 06/01/2026 * b. End Date: 09/29/2028

18. Estimated Funding ($):

* a. Federal	[redacted]
* b. Applicant	[redacted]
* c. State	0.00
* d. Local	0.00
* e. Other	0.00
* f. Program Income	0.00
* g. TOTAL	[redacted]

*** 19. Is Application Subject to Review By State Under Executive Order 12372 Process?**

☐ a. This application was made available to the State under the Executive Order 12372 Process for review on ________.

☐ b. Program is subject to E.O. 12372 but has not been selected by the State for review.

☒ c. Program is not covered by E.O. 12372.

*** 20. Is the Applicant Delinquent On Any Federal Debt? (If "Yes," provide explanation in attachment.)**

☐ Yes ☒ No

If "Yes", provide explanation and attach

Add Attachment | Delete Attachment | View Attachment

21. *By signing this application, I certify (1) to the statements contained in the list of certifications and (2) that the statements herein are true, complete and accurate to the best of my knowledge. I also provide the required assurances** and agree to comply with any resulting terms if I accept an award. I am aware that any false, fictitious, or fraudulent statements or claims may subject me to criminal, civil, or administrative penalties. (U.S. Code, Title 18, Section 1001)**

☒ ** I AGREE

** The list of certifications and assurances, or an internet site where you may obtain this list, is contained in the announcement or agency specific instructions.

Authorized Representative:

Prefix: * First Name: Scott

Middle Name:

* Last Name: Osterholt

Suffix:

* Title: Managing Director Federal Grants & Broadband

* Telephone Number: [redacted] Fax Number:

* Email: [redacted]

* Signature of Authorized Representative: [redacted] * Date Signed: [redacted] 46 AM I

DISCLOSURE OF LOBBYING ACTIVITIES

Complete this form to disclose lobbying activities pursuant to 31 U.S.C.1352

OMB Number: 4040-0013
Expiration Date: 02/28/2025

Review Public Burden Disclosure Statement

1. * Type of Federal Action:
- [ ] a. contract
- [x] b. grant
- [ ] c. cooperative agreement
- [ ] d. loan
- [ ] e. loan guarantee
- [ ] f. loan insurance

2. * Status of Federal Action:
- [ ] a. bid/offer/application
- [x] b. initial award
- [ ] c. post-award

3. * Report Type:
- [x] a. initial filing
- [ ] b. material change

4. Name and Address of Reporting Entity:

[x] Prime [ ] SubAwardee

* Name: Wheeling Power Company
* Street 1: 1 Riverside Plaza | Street 2:
* City: Columbus | State: OH: Ohio | Zip: 43215-2373
Congressional District, if known:

5. If Reporting Entity in No.4 is Subawardee, Enter Name and Address of Prime:

6. * Federal Department/Agency: DOE

7. * Federal Program Name/Description: Restoring Reliability: Coal Recommissioning and Modernization DE-FOA-0003605

CFDA Number, *if applicable:* 81.255

8. Federal Action Number, *if known:*

9. Award Amount, *if known:* $

10. a. Name and Address of Lobbying Registrant:

Prefix: | * First Name: Kate | Middle Name:
* Last Name: Marks | Suffix:
* Street 1: 750 9th St NW | Street 2:
* City: Washington | State: DC: District of Columbia | Zip: 20001

b. Individual Performing Services (including address if different from No. 10a)

Prefix: | * First Name: Kate | Middle Name:
* Last Name: Marks | Suffix:
* Street 1: 750 9th St NW | Street 2:
* City: Washington | State: DC: District of Columbia | Zip: 20001

11. Information requested through this form is authorized by title 31 U.S.C. section 1352. This disclosure of lobbying activities is a material representation of fact upon which reliance was placed by the tier above when the transaction was made or entered into. This disclosure is required pursuant to 31 U.S.C. 1352. This information will be reported to the Congress semi-annually and will be available for public inspection. Any person who fails to file the required disclosure shall be subject to a civil penalty of not less than $10,000 and not more than $100,000 for each such failure.

* Signature: [redacted]

*Name: Prefix: | * First Name: Scott | Middle Name:
* Last Name: Osterholt | Suffix:

Title: Managing Director Federal Grants & Broadband | Telephone No.: [redacted] | Date: [redacted]

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Standard Form - LLL (Rev. 7-97)

Control Number: 3605-1510

Techno-Economic Analysis
Mitchell Mechanical Draft Cooling Tower Modernization Project

Notice of Restriction on Use and Disclosure of Information: *All pages of this document may contain business sensitive, trade secret, proprietary, or otherwise confidential information that is exempt from public disclosure, as indicated by highlight. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance, loan, or Other Transaction Agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source.*

The Company requires a capital investment in Unit 2's cooling tower to ensure the continued safe and reliable operation of the Mitchell Plant for its customers.

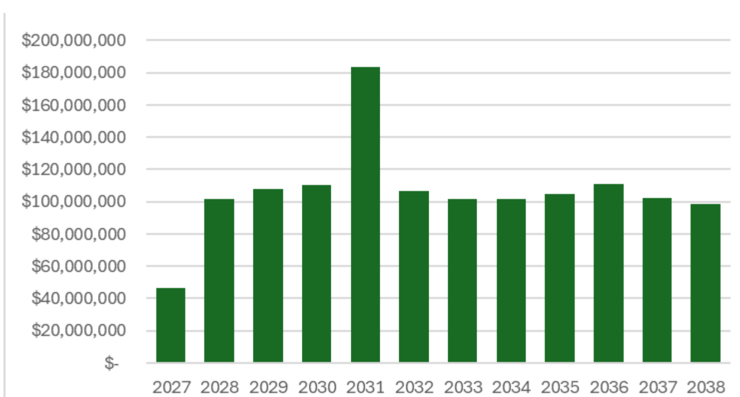
Alternatives Considered

Four options were evaluated to address the Unit 2 cooling tower at the Mitchell Plant. Option 1 was to expand and extend the exterior shell reinforcement project. Option 2 was to retire Unit 2 and partially demolish the existing Unit 2 cooling tower. Option 3 was to construct a new mechanical draft cooling tower and partially demolish the existing Unit 2 cooling tower. Option 4 was to reduce the height of the existing Unit 2 cooling tower and continue with a reduced scope of exterior shell reinforcement.

Economic Analysis

In this type of analysis, the Company aims to find the most cost-effective option for its customers. The Company examined the Present Value (PV) of the Revenue Requirements (RRs) from 2027-2038 and the Average Yearly Revenue Requirements. RR is the focus of the economic analysis, as this is what the customer will ultimately pay through their bills for the project. The Company works to provide safe, reliable power to customers through the least costly option.

Option 2 – retiring the unit – is the least viable, as it would lead to a capacity and energy shortfall beginning in 2026, and result in high costs for customers. This shortfall, along with further economic analysis of replacing the capacity provided through market purchases and building a new generation resource, led to the option not being pursued or recommended. [redacted],



[redacted]

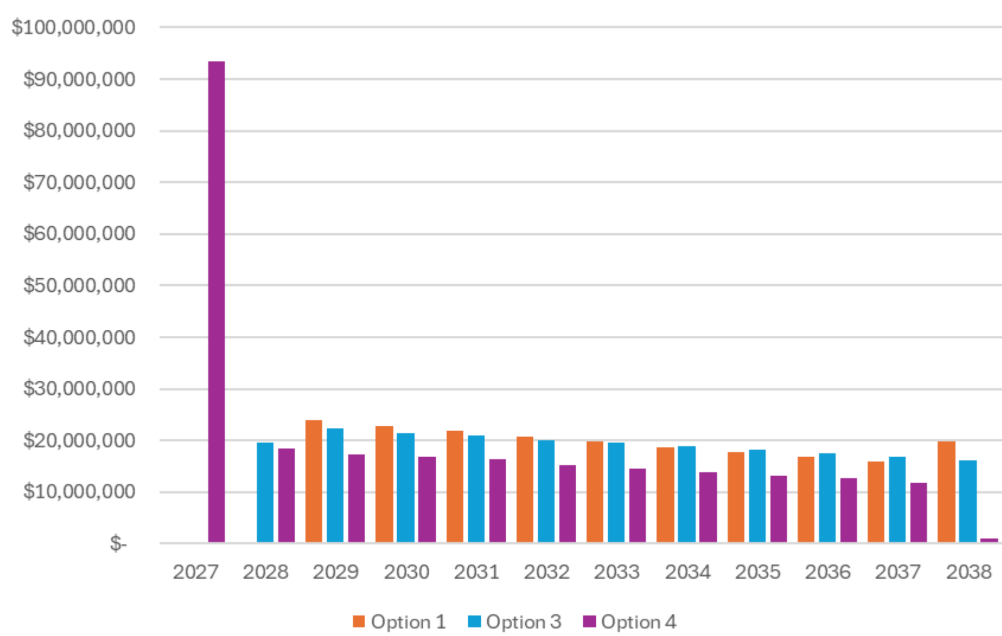
[redacted] However, if Option 3 were not available to the Company, this option would have to be reconsidered, given the high-risk profile of Options 1 and 4. The results of the PV Revenue Requirement and Average Revenue Requirement were as follows:

	Option 2
PV RR 2027 - 2038	[redacted]
Average RR 2027-2038	[redacted]

Discount Rate for PV calculation: 6.95%

The other options were deemed more viable, and an economic analysis was conducted to determine the least costly option for customers, while also evaluating the qualitative benefits and risks associated with each option. The analysis considered the capital costs of the options and determined the revenue requirement that would be collected from customers. Other inputs into the economic analysis included the option's life, when the option could be placed in service, whether an outage would be required for construction, and any lost energy margins due to derates (decreases in capacity) of the unit. The results of the PV RR and Average RR were as follows for Options 1, 3, and 4:

	Option 1	**Option 3**	**Option 4**
PV RR 2027-2038	[redacted]	[redacted]	[redacted]
Average RR 2027-2038	[redacted]	[redacted]	[redacted]



[redacted]

The economics for customers only improve if the Company were to be granted $50 million for the project, as it would reduce the cost to customers by roughly $6 million per year.

	Option 3 with Grant
PV RR 2027 - 2038	[redacted]
Average RR 2027-2038	[redacted]

Years with zero revenue requirement (due to the timing of when the project can go into service) were omitted from the Average RR calculation so as not to skew the results.
Discount rate for PV calculations: 6.95%.

Ultimately, Option 3 was selected for the construction of a new mechanical draft tower. This option provides the lowest average cost to customers – 80% cheaper than retiring the unit – and increases optionality for the future of Mitchell Plant operations due to the longer life of the new mechanical draft tower.

Control Number: 3605-1510

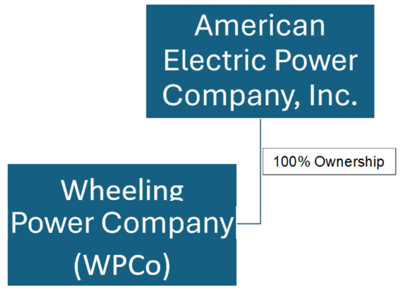
Transparency of Foreign Connections

Mitchell Mechanical Draft Cooling Tower Modernization Project

Disclosure Information	
***Entity Name**	Wheeling Power Company
***Website Address**	https://www.appalachianpower.com/
***Mailing Address**	1 Riverside Plaza, Columbus, OH 43215
***Project Participants Party to ANY Malign Foreign Talent Recruitment Program**	AEP does not work with Foreign Government Talent Recruitment Programs (FGSTRP).
Country of Risk Joint Venture or Subsidiary	None at this time.
Current or Pending Foreign Contractual or Financial Obligation	None at this time.
Percentage Foreign Ownership or Control	None at this time.
Percentage Country of Risk Ownership	0%
Percentage Country of Risk Investment	0%
***Country of Risk Technology Licensing of Intellectual Property Sales**	None at this time.
***Foreign Equipment**	None at this time.
Foreign Entity Relationships	None at this time.
List of Company Directors (and Board Observers)	Please refer to the Applicant's most current Annual Report, filed with the Securities and Exchange Commission.
Complete Capitalization Table	Please refer to the Applicant's most current Annual Report, filed with the Securities and Exchange Commission.
Principal Place of Incorporation for Equity Holders	Please refer to the Applicant's most current Annual Report, filed with the Securities and Exchange Commission.
Rounds of Financing Table	Please refer to the Applicant's most current Annual Report, filed with the Securities and Exchange Commission.

Control Number: 3605-1510

Organization Chart



AMERICAN ELECTRIC POWER

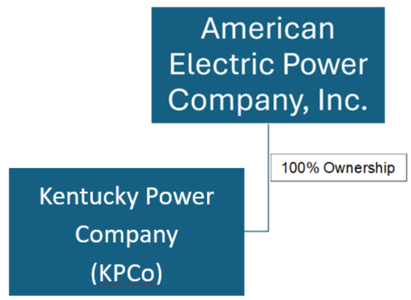
Control Number: 3605-1510

Transparency of Foreign Connections

Mitchell Mechanical Draft Cooling Tower Modernization Project

Disclosure Information	
***Entity Name**	Project lead organization: Wheeling Power Company Partner company associated with this disclosure: Kentucky Power Company
***Website Address**	https://www.kentuckypower.com/
***Mailing Address**	1 Riverside Plaza, Columbus, OH 43215
***Project Participants Party to ANY Malign Foreign Talent Recruitment Program**	AEP does not work with Foreign Government Talent Recruitment Programs (FGSTRP).
Country of Risk Joint Venture or Subsidiary	None at this time.
Current or Pending Foreign Contractual or Financial Obligation	None at this time.
Percentage Foreign Ownership or Control	None at this time.
Percentage Country of Risk Ownership	0%
Percentage Country of Risk Investment	0%
***Country of Risk Technology Licensing of Intellectual Property Sales**	None at this time.
***Foreign Equipment**	None at this time.
Foreign Entity Relationships	None at this time.
List of Company Directors (and Board Observers)	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.
Complete Capitalization Table	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.

Control Number: 3605-1510

Principal Place of Incorporation for Equity Holders	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.
Rounds of Financing Table	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.
Organization Chart	

Control Number: 3605-1510

Transparency of Foreign Connections

Mitchell Mechanical Draft Cooling Tower Modernization Project

Disclosure Information	
***Entity Name**	Project lead organization: Wheeling Power Company Partner company associated with this disclosure: American Electric Power Service Corporation
***Website Address**	https://www.aep.com/
***Mailing Address**	1 Riverside Plaza, Columbus, OH 43215
***Project Participants Party to ANY Malign Foreign Talent Recruitment Program**	AEP does not work with Foreign Government Talent Recruitment Programs (FGSTRP).
Country of Risk Joint Venture or Subsidiary	None at this time.
Current or Pending Foreign Contractual or Financial Obligation	None at this time.
Percentage Foreign Ownership or Control	None at this time.
Percentage Country of Risk Ownership	0%
Percentage Country of Risk Investment	0%
***Country of Risk Technology Licensing of Intellectual Property Sales**	None at this time.
***Foreign Equipment**	None at this time.
Foreign Entity Relationships	None at this time.
List of Company Directors (and Board Observers)	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.
Complete Capitalization Table	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.

Control Number: 3605-1510

Principal Place of Incorporation for Equity Holders	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.
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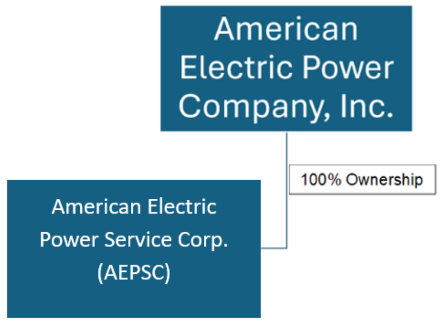
Organization Chart	

Control Number: 3605-1510

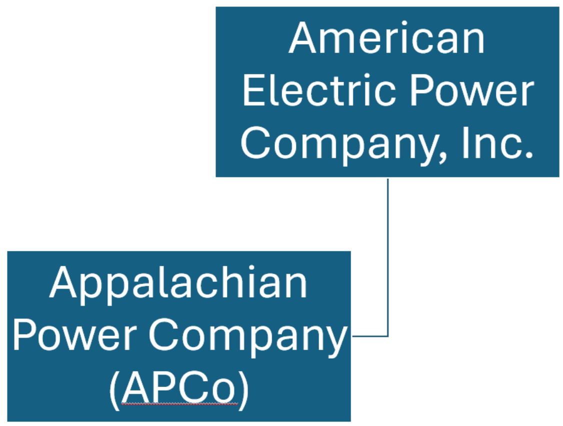
Transparency of Foreign Connections

Mitchell Mechanical Draft Cooling Tower Modernization Project

Disclosure Information	
***Entity Name**	Project lead organization: Wheeling Power Company Partner company associated with this disclosure: Appalachian Power Company
***Website Address**	https://www.appalachianpower.com/
***Mailing Address**	1 Riverside Plaza, Columbus, OH 43215
***Project Participants Party to ANY Malign Foreign Talent Recruitment Program**	AEP does not work with Foreign Government Talent Recruitment Programs (FGSTRP).
Country of Risk Joint Venture or Subsidiary	None at this time.
Current or Pending Foreign Contractual or Financial Obligation	None at this time.
Percentage Foreign Ownership or Control	None at this time.
Percentage Country of Risk Ownership	0%
Percentage Country of Risk Investment	0%
***Country of Risk Technology Licensing of Intellectual Property Sales**	None at this time.
***Foreign Equipment**	None at this time.
Foreign Entity Relationships	None at this time.
List of Company Directors (and Board Observers)	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.
Complete Capitalization Table	Please refer to the Applicant’s most current Annual Report, filed with the Securities and Exchange Commission.

APPALACHIAN POWER
An AEP Company

Control Number: 3605-1510

Principal Place of Incorporation for Equity Holders	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.
Rounds of Financing Table	Please refer to the most current Annual Report, filed with the Securities and Exchange Commission.
Organization Chart	

DATA REQUEST

KPSC PHDR_7	Refer to the November 18, 2025 H.V.T. at 11:39:05 discussing the completion of an annual 10 year capital budget for Mitchell Plant. Provide a copy of the most recent capital budget prepared for the Mitchell Plant.

RESPONSE

Please see KPCO_R_KPSC_PHDR_7_ConfidentialAttachment1 for the 10-year capital budget for the Mitchell Plant.

Witness: Joshua D. Snodgrass

KPCO_R_KPSC_PHDR_7_ConfidentialAttachment1 is redacted in its entirety.

DATA REQUEST

KPSC PHDR_8	Refer to the November 18, 2025 H.V.T. at 11:32:05. a. Explain the frequency of monitoring recommended by engineers for the cooling tower at Mitchell Unit 2. b. Explain the criteria, if any, that engineers are looking for in the inspections and what circumstances, if any, would necessitate an immediate or emergency repair to keep Mitchell Unit 2 operational.

RESPONSE

a. The monitoring program is comprised of four key elements: continuous structural monitoring, annual drone inspections, bi-annual LiDAR assessments, and Wind Weather monitoring. Below is a description of each component:

Continuous Structural Monitoring: This involves the use of three automated laser Total Station survey devices strategically positioned around the tower to provide full coverage. These devices continuously measure survey prisms affixed to the tower. In total, there are 121 prisms installed on the shell, which are being monitored continuously around the clock for structural movement. In the event that any unusual movement is detected, a notification is promptly sent to AEP. Additionally, the collected data is reviewed monthly by an engineer to ensure ongoing safety and structural integrity.

Drone Assessment: This process involves deploying a drone around the tower to capture images and identify areas of concrete distress conditions. A 3D model of the structure is then created from the stitched together images to assess the tower's condition. This will be conducted annually.

LiDAR Assessment: This assessment utilizes laser scanning equipment to produce a comprehensive 3D scan of the tower. New scans will be compared to previous scans to identify any changes in the tower's shape. This evaluation will be conducted bi-annually.

Wind Weather Monitoring: This system consists of eight weather stations located around the tower. If excessive wind is detected, AEP will be alerted. A visual inspection can then be performed and an engineering assessment completed if needed.

b. Engineers will utilize the monitoring techniques described above to identify any unusual movements, signs of concrete distress such as cracking or spalling, and changes to the overall shape of the tower. Should any anomalies be detected, an engineering assessment will be conducted to evaluate the need for immediate actions or repairs.

Witness: Joshua D. Snodgrass

DATA REQUEST

KPSC PHDR_9

Refer to the November 18, 2025 H.V.T. at 02:54:05-02:55:18.

a. Provide copies of Section 3 and Section 5 of the *2025 Quarterly State of the Market Report for PJM: January through September* and Section 3 and Section 5 of the 2021 State of the Market Report for PJM.

b. Confirm that the reports provided in response to part a. are the reports that were referenced in the hearing testimony referred. If those are not the reports that were referred to in the hearing testimony, or if different sections of the reports were being referred to, provide such reports or sections.

RESPONSE

a. Please see KPCO_R_KPSC_PHDR_9_Attachment1 for the requested State of the Market Reports for PJM. These reports along with any errata information can be publicly found at
https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025.shtml.

b. Confirmed.

Witness: Alex E. Vaughan

Q3

State of the Market Report for PJM

January through September

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

11.13.2025

2025

Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM), and is also known as the Independent Market Monitor for PJM (IMM), submits this *2025 Quarterly State of the Market Report for PJM: January through September*.[2] [3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement (RAA), the Consolidated Transmission Owners Agreement (CTOA) or other tariffs that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).
2 OATT Attachment M.
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2025 Quarterly State of the Market Report for PJM: January through September*.

Table of Contents

Introduction

Q3 2025 in Review

Reliability is a core goal of PJM. Maintaining and improving competitive markets should also be a core goal of PJM. The goal of competition in PJM is to provide customers reliable wholesale power at the lowest possible price, but no lower. The PJM energy markets have done that. The PJM markets work, even if not perfectly. The results of PJM markets were reliable in the first nine months of 2025. The results of the energy market were competitive in the first nine months of 2025. The results of the 2025/2026 and 2026/2027 capacity markets were not competitive. The PJM markets bring customers the benefits of competition when the market rules allow competition to work and prevent the exercise of market power.

The PJM energy and capacity markets are components of the PJM market; both are essential to providing reliable energy to customers at the lowest possible price. The energy market results incorporate immediate short term conditions including weather, unit availability, actual load, transmission limitations, and fuel availability and costs. The capacity market results incorporate load forecasts and the response of investors in resources to expected market conditions. The energy market and the capacity market face interrelated challenges. There are interactive effects between the incentives in the energy market and the incentives in the capacity market.

There are clear warning signs for the capacity market. The capacity market was short of meeting its reliability objective in the most recent capacity auction for the 2026/2027 BRA. PJM was also short of meeting its IRM target as of June 1, 2025, on an ICAP and a UCAP basis. The amount that PJM is short capacity is relatively small, around 200 MW in both the BRA and the actual available capacity. The price impacts have been very large and will be even larger in the near term even if the issues are addressed in a timely manner.

Data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the capacity market would not have seen the same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA and the 2026/2027 BRA, and the currently expected tight supply conditions and high prices for subsequent capacity auctions.

Holding aside all the other issues associated with the 2026/2027 BRA, existing and forecast data center load by itself resulted in a significant increase in the 2026/2027 BRA revenues. Based on actual auction clearing prices and quantities and uplift MW, inclusion of existing and forecast data center load in the peak load forecast for 2026 resulted in a $7,271,197,971 or an 82.1 percent increase in capacity market revenues for the 2026/2027 RPM Base Residual Auction. Inclusion of existing and forecast data center load growth resulted in a combined total increase in capacity market revenues for the 2025/2026 BRA and the 2026/2027 BRA of $16,603,301,829. This total will continue to grow until the issues associated with the additions of large data center loads are addressed. The impact will increase significantly in the 2028/2029 BRA currently scheduled for June 2026, when the maximum and minimum prices defined by the Agreement are no longer effective.

The impact on the 2026/2027 BRA revenues would have been higher had PJM not used the restricted VRR curve.[1] If the 2026/2027 BRA had been run with an unrestricted VRR curve, total revenues would have been $19,294,286,100, an increase of $3,169,915,210, or 19.7 percent, compared to the actual auction results. Without the restricted VRR curve, including existing and forecast data center load in the 2026 peak load forecast would have resulted in capacity market revenues of $19,294,286,100, a $14,189,483,234 or a 278.0 percent increase in capacity market revenues for the 2026/2027 RPM BRA compared to what RPM revenues would have been without the impact of data center load.

Large data center load additions have already had a significant impact and will have additional significant impacts on other customers as a result of

1 On December 30, 2024, in Docket No. EL25-46-000, Governor Josh Shapiro and the Commonwealth of Pennsylvania filed a complaint against PJM asserting that the maximum price for PJM's capacity auctions is unjust and unreasonable. The Governor and PJM reached an Agreement. On February 20, 2025, in Docket No. ER25-1357-000, pursuant to FPA section 205, PJM submitted proposed revisions to its Tariff to establish a specific maximum price and minimum price for all RPM auctions for the 2026/2027 and 2027/2028 Delivery Years, consistent with the Agreement. The resultant VRR curve is termed the restricted VRR curve.

higher transmission costs, higher energy market prices and higher capacity market prices.

In order to address these issues related to the addition of large new data center loads, the PJM Board of Managers created a Critical Issue Fast Path (CIFP) stakeholder process that began on August 18, 2025, and is expected to conclude on November 19, 2025.

Markets cannot solve all problems and it is not enough to simply assert that the market will solve all these problems. The wholesale power markets created by FERC need rules and include rules. FERC relies on competitive markets to be a more effective substitute for economic regulation. FERC's rules about market design and rules governing demand and supply are essential to creating the conditions under which markets can work, in significant part because there is endemic structural market power in the capacity market. The decisions about the interconnection of large new data center loads when there is not enough capacity to maintain system reliability are public, regulatory decisions because they are about competitive outcomes that are in the interests of all market participants. PJM markets are not laissez faire markets.

It is clear that continuing to simply accept the interconnection of large data center loads that cannot be served reliably because there is not adequate dispatchable capacity, is not a reasonable path forward and is not a market solution and is not a solution of any kind. That path leads to continued shortfalls, increased reliability issues, continued maximum prices, and continued calls to abandon markets and return to cost of service regulation. The calls to return to cost of service regulation have continued to grow from the regulated transmission owners and from sectors of the supply community that prefer customer subsidies to markets. The question is how to serve large new data center loads without imposing the related costs and risks on other customers.

The current supply of capacity in PJM is not adequate to meet the demand from large data center loads and will not be adequate in the foreseeable future. This is a simple factual issue. There is not enough capacity currently to meet the data center load. The solution is not to create reliability issues and wealth transfer issues by clearing the capacity market at the maximum price and at a quantity less than the reliability requirement by allowing the ongoing interconnection of large data center loads without adequate generation to serve them.

The market solution is to establish a queue for the addition of large new data center loads which would not be interconnected until there is adequate capacity to serve them. The market solution would create an expedited fast track load and generation interconnection process for large new data center loads that bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. This solution to the issues created by the addition of unprecedented amounts of large data center load does not require a massive wealth transfer. It is essential to have a pragmatic market solution that is consistent with and sustains efficient and competitive PJM markets rather than to create the conditions for a return to cost of service regulation.

All loads should be served. All loads should be served reliably. The process for adding large data center loads should be transparent. All loads should benefit from competitive markets. All loads should have equal access to the transmission system. All loads should be treated as full transmission customers. All loads and generation are and should be on the grid and the grid is highly interconnected.

There are a number of other approaches to address the current capacity market conditions at the wholesale level. In addition to general agreement that load forecasts should be more accurate, the approaches include features that fall into two broad categories: allow bilateral contracts to remove existing capacity to serve data center loads, and allow data centers to be treated as demand side resources. These proposals exacerbate reliability issues and customer cost issues and fail to directly address the real issue.

The temptation to create regulatory fictions that would permit the interconnection of large new data center loads without matching capacity should be resisted. The simple fact is that if significant new loads are added without adding new capacity, PJM markets will be less reliable and more costly. New capacity is needed to serve the new loads.

The proposals to allow data center loads to remove existing capacity from the market and dedicate it to the data centers would simply shift the costs of serving data center load to all other customers. The assertion that this is a solution to the issues is a regulatory fiction. This approach includes proposals to declare that resources would retire but for such a bilateral contract and to define an existing resource as new based on investment in the existing resource. Both arguments would serve as a rationale for removing existing capacity resources from the market and dedicating them to data centers. As with the co-location proposals, the result would be chaos in the PJM markets. It would not be possible to serve existing customers reliably until matching amounts of new generation are built. The impacts on capacity and energy market prices would exceed the demonstrated impacts to date.

The assertion that large new data center loads can be demand side resources and do not require new capacity is a regulatory fiction. The unintended consequences would be overwhelming, given the very large level of such loads. Holding aside the impacts on energy prices and reliability, the direct impact of adding a MW of demand side resources for every MW of data center load would be to increase capacity market prices.

If 20,000 MW of new data center load were added and all 20,000 MW of this load were offered in the capacity market as emergency demand side resources, the MMU estimates that the increased cost of capacity would be around $396 million per year to existing customers.[2] If 20,000 MW of new data center load were added and 90 percent or less of this load were offered in the capacity market as emergency demand side resources, the IMM estimates that the increased cost of capacity would be around $5.48 billion per year to existing customers.[3] There would be comparable impacts on the cost of capacity for any proposal that results in an equivalent or smaller level of emergency demand resources in UCAP terms, e.g. from lower ELCC derating factors. The impact on energy market prices of adding data center load without new generation would also be in the billions of dollars annually. The additional load without new generation affects energy prices directly by requiring generation from more expensive resources on the supply curve and by increasing the probability of shortage pricing. Emergency demand resources also directly affect clearing prices based on the offered strike prices which can be as high as $1,849 per MWh.

In addition to the immediate increase in both capacity and energy costs, there are significant issues with actually expanding the role of emergency demand side resources in a massive way. Demand side response when called is effectively voluntary based on the relatively weak incentives to respond, despite the fact that the tariff states that reductions are required. If demand side resources do not respond when called, any actual performance penalties can be overridden by test results, if the performance issue is not during a PAI event. PJM does not have the authority to enforce reductions in load from emergency demand resources. Given the 99.999 percent reliability requirements of data centers, the option to interrupt these customers is not a viable solution from the data centers' or the other customers' perspective unless the conditions for interruption are so limited as to impose only a small probability of interruption. The actual rules for exactly when PJM calls emergency demand resources are not clear. There is no fixed order of emergency procedures. Many of the proposals for the demand side option in the CIFP stakeholder process would significantly limit the number and duration of calls on the emergency demand resources. Those limits are not consistent with the actual impact of the large new data center loads on the system which will require frequent and potentially long reductions in load as a result of the extremely high level of such loads. Under these proposals, PJM would rely on demand side resources for all of its reserve margin and more.

In addition, the proposals that include the demand side option in place of adding actual generation capacity do not make the demand side option a mandatory condition for interconnection and do not provide a mechanism

2 The MMU estimated the impact by clearing the 2026/2027 BRA without maximum and minimum prices, with 20,000 MW additional peak load, and 20,000 ICAP MW of additional demand resources offered at $0 per MW-day in the Rest of the RTO and comparing it against the 2026/2027 BRA results without maximum and minimum prices. For this sensitivity analysis, the MMU used the 2027/2028 FPR (0.926) for the additional 20,000 MW of data center load and the 2027/2028 ELCC based AUCAP factor (0.92) for the additional demand resources offered, while holding everything else the same as the 2026/2027 BRA without maximum and minimum prices.

3 Adding data center load that is not fully offset by demand response resources is equivalent to increasing the demand for capacity. The MMU sensitivity analysis shows that the additional load would result in increasing the cost of capacity to existing customers through higher capacity market clearing prices.

for PJM to enforce such demand side offers from new data center loads. As a result, the demand side option is voluntary and effectively equivalent to the status quo that has already increased the costs to PJM customers by about $16.6 billion over the last two capacity auctions, in addition to the impact on energy costs.

PJM's initial non capacity backed load (NCBL) option was the only demand side proposal that could actually work, even in theory. PJM's NCBL proposal would have made interruptions mandatory when PJM needed the capacity to serve the load that had actually paid for the capacity. However, even PJM's proposal was not enforceable. PJM does not have the authority to curtail loads of specific customers. Even the strongest and cleanest approach to treating large new data center loads as emergency capacity market demand resources cannot work. The other such proposals are also unworkable and unenforceable and will result in the shift of significant costs and risks to the other PJM customers.

Implementing a load queue for large new data center loads is the only enforceable way to address the impacts of such loads and to require large new data center loads to pay for a significant part of the costs and risks that they would otherwise impose on other customers. The load queue provides strong and enforceable incentives to bring new capacity to the market, which is the point.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices for both price decreases and price increases. Energy prices increased in the first nine months of 2025 from the first nine months of 2024. The real-time load-weighted average LMP in the first nine months of 2025 increased $16.20 per MWh, or 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh. The PJM energy market met new winter and summer peak loads in the first nine months of 2025.

Of the $16.20 per MWh increase, $9.85 per MWh (60.8 percent) was in the fuel and consumables cost components of LMP, $2.07 per MWh (12.8 percent) was in the transmission constraint penalty factor component of LMP, $0.85 per MWh (5.2 percent) was in the market power components of LMP, -$0.16 per MWh (-1.0 percent) was in the emissions cost components of LMP, and $1.14 per MWh (7.0 percent) was in the scarcity component of LMP. The strike prices of pre-emergency demand response called on by PJM during the hot weather days in June and July increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP.

The total cost of wholesale power increased in the first nine months of 2025, from the first nine months of 2024. Energy (61.3 percent), capacity (13.5 percent) and transmission (23.1 percent) are the three largest components of the total cost of wholesale power, comprising 97.9 percent of the total cost per MWh in the first nine months of 2025. The total cost of wholesale power increased $24.10 per MWh, or 43.7 percent, from $55.18 per MWh in the first nine months of 2024 to $79.28 per MWh in the first nine months of 2025. Of the $24.10 increase, the total cost of energy increased by $15.91 per MWh, 48.7 percent, the total cost of capacity increased by $7.13 per MWh, 200.8 percent, and the total cost of transmission increased by $0.94 per MWh, 5.4 percent.

In the first nine months of 2025, generation from coal units increased 16.1 percent, generation from natural gas units decreased 1.6 percent, generation from oil units increased 25.8 percent, generation from wind units increased 1.8 percent, and generation from solar units increased 46.4 percent compared to the first nine months of 2024.

Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices, gas prices and coal prices increased in the first nine months of 2025 compared to the first nine months of 2024. The net effects were that in the first nine months of 2025, average energy market theoretical net revenues increased by 30 percent for a new combustion turbine (CT), increased by 35 percent for a new combined cycle (CC), increased by 148 percent for a new coal plant (CP), increased by 46 percent for a new nuclear plant, increased by 279 percent for a new diesel (DS), increased by 52 percent for a new onshore wind installation, increased by 49 percent for a new offshore wind installation and increased by 42 percent for a new solar installation.

The real-time hourly average load in the first nine months of 2025 increased by 3.0 percent from the first nine months of 2024, from 90,917 MWh to 93,683 MWh.

While there are multiple centrifugal forces acting on PJM markets, there are still options available to maintain well functioning markets. Steps that can and should be taken immediately to offset those forces include: define and implement a queue for the addition of large new data center loads; implement a bring your own new generation option for the interconnection of large new data center loads; improve the ELCC/CP capacity market design; clarify the goals and design of the PJM reserve products; clarify the rules for advance commitment of generation for extreme weather; identify the availability of firm gas supply; ensure transparent information from pipelines; identify the need for dual fuel capacity; modify the RMR process; add comprehensive expedited queue options under PJM control to replace retiring resources and address immediate reliability issues; ensure integrated PJM transmission and reliability planning; ensure that large new loads are not subsidized or given preferential treatment; ensure that market power mitigation measures are strengthened and clarified, not eroded; facilitate more competition for transmission projects; and include direct comparisons between generation and transmission options to address reliability issues.

The evolution of wholesale power markets is far from complete. The PJM markets need rules in order to provide reliable energy through competition. The foundational principle of using markets, with rules to prevent the exercise of market power and provide competitive results, is essential. Private investors, regardless of technology or subsidies, will put capital at risk and earn compensatory returns in markets that are not skewed in favor of any specific technology and in markets that are stable and that do not add risk and volatility. The core elements of the PJM market design remain robust. The use of locational marginal prices (LMP) in the energy market and partially locational prices in the capacity market continue to be essential to getting the price signals right. Technological and policy changes do not require that the core elements change. However, the market design can and must be improved and made more reliable and more efficient and more competitive. The current PJM ELCC capacity market design adds unnecessary risk and volatility that are not part of the market fundamentals. The ELCC approach needs to be applied on a unit specific basis, incorporate hourly supply and demand matching, and pay resources based on actual availability and performance rather than on assumed performance derived from a very limited data set of misinterpreted performance results based on unrepresentative extreme historical weather and specific PJM commitment and dispatch decisions. The capacity market also needs to eliminate artificial PAI risk that leads to uneconomic retirements and exits from PJM. The basic logic of market power mitigation in both energy and capacity markets needs to be restored. The queue process should allow for a comprehensive, expedited process to resolve identified reliability issues. There should be a load queue for the addition of large new data center loads. The queue process should include an expedited process for large data center load additions that bring their own generation. The markets will also need support from regulators whose decisions create and/or limit the options available to investors in PJM resources. Competition to build transmission, to implement dynamic line ratings (DLR) and to add grid enhancing technologies (GETs) should be expanded.

In the interests of all market participants, PJM, its current and potential market participants and stakeholders, PJM states, and the FERC will need to continue to work constructively to refine the competitive market design and to ensure the continued effectiveness of PJM markets in providing customers wholesale power at the lowest possible price, but no lower.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM market summary statistics: January through September, 2024 and 2025[4]

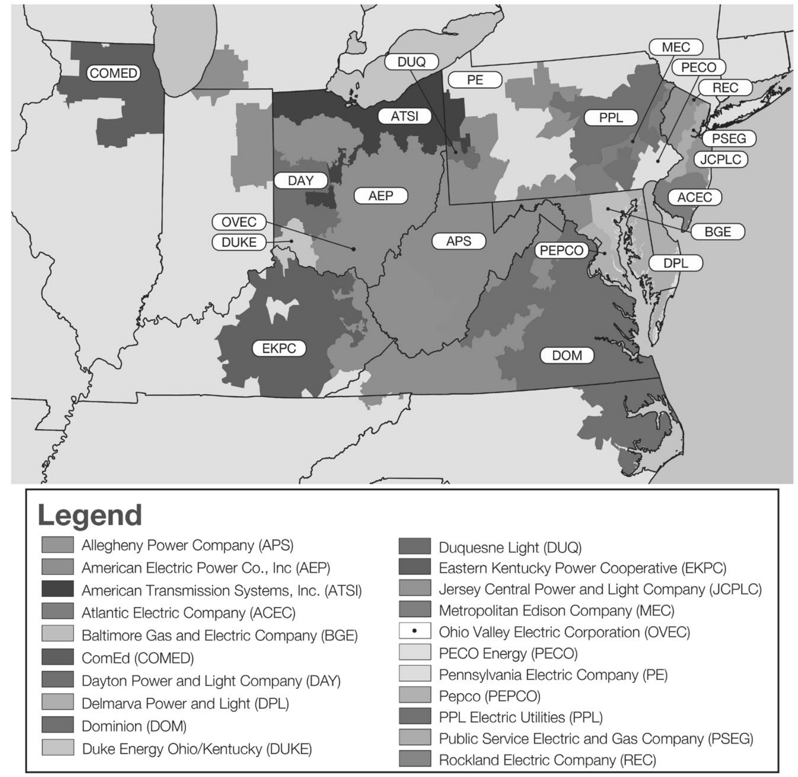
	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change
Average Hourly Load Plus Exports (MWh)	96,746	100,114	3.5%
Average Hourly Generation Plus Imports (MWh)	98,593	102,018	3.5%
Peak Load Plus Net Export (MWh)	149,398	158,789	6.3%
Peak Load Excluding Export (MWh)	148,890	156,256	4.9%
Installed Capacity at September 30 (MW)	177,032	181,729	2.7%
Load Weighted Average Real Time LMP ($/MWh)	$34.31	$50.51	47.2%
Total Congestion Costs ($ Million)	$1,385.80	$2,233.80	61.2%
Total Uplift Credits ($ Million)	$218.5	$660.6	202.3%
Total PJM Billing ($ Billion)	$39.07	$57.77	47.9%

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2025, had installed generating capacity of 181,729 megawatts (MW) and 1,102 members including market buyers, sellers and traders of electricity in a region including more than 67 million people in 21 control zones and all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia (Figure 1-1).[5] [6] [7]

As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

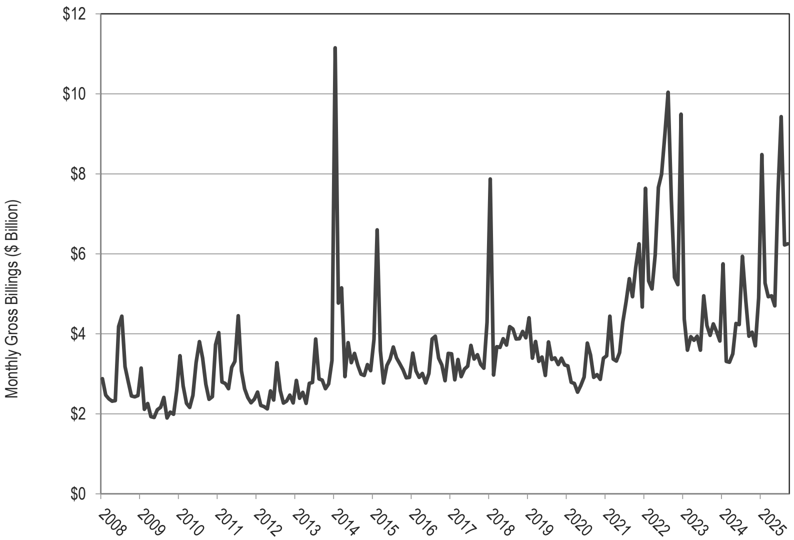
Figure 1-1 PJM's footprint and its 21 control zones



4 In Table 1-1, the MMU used the total PJM billing values provided by PJM through 2018. Starting in 2019, the total PJM billing values in Table 1-1 are modified by the MMU, to more accurately reflect PJM total billing. The total PJM billing shown in Table 1-1 is different from the total cost shown in Table 1-9. The total PJM billing in Table 1-1 represents the total dollars (charges) that pass through the PJM settlement process, while the total cost shown in Table 1-9 represents the portion of the total billing associated with the cost to load and includes additional costs to load accounted for outside the PJM settlement process.
5 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
6 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
7 See the *2024 Annual State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Overview" for maps showing the PJM footprint and its evolution prior to 2024.

In the first nine months of 2025, PJM had gross billings of $57.77 billion, an increase of 47.9 percent from $39.07 billion in the first nine months of 2024. (Figure 1-2).

Figure 1-2 Monthly PJM billings ($ Billion): January 2008 through September 2025[8]



PJM operates the day-ahead energy market, the real-time energy market, the capacity market, the regulation market, the synchronized reserve market, the secondary reserve market and the financial transmission rights (FTRs) markets.

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented FTRs on May 1, 1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM modified the regulation market design and added a market in Synchronized Reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM capacity market effective June 1, 2007. PJM implemented the DASR market on June 1, 2008, and eliminated it on October 1, 2022. PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.[9] [10]

8 In Figure 1-2, the MMU used the total PJM billing values provided by PJM through 2018. Starting in 2019, the total PJM billing values in Figure 1-2 are modified by the MMU, to more accurately reflect PJM total billing. The total PJM billing shown in Figure 1-2 is different from the total cost shown in Table 1-9. The total PJM billing in Figure 1-2 represents the total dollars (charges) that pass through the PJM settlement process, while the total cost shown in Table 1-9 represents the portion of the total billing associated with the cost to load and includes additional costs to load accounted for outside the PJM settlement process.

9 See also the *2024 Annual State of the Market Report for PJM*, Appendix A: "PJM Overview."

10 Analysis of 2025 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: COMED, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DUQ) and Dominion (DOM). In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DUKE) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2025, see *2024 Annual State of the Market Report for PJM*, Appendix A: "PJM Overview."

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2025, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the IMM, the Market Monitoring Unit or the MMU.

For each PJM market, the market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the cost, demand, and ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for the ownership of assets and the relationship among the pattern of ownership, the resource costs, and the market demand using actual market conditions with both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referred to as participant conduct.

Market performance refers to the outcomes of the market. Market performance results from the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of short run marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market outcomes, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

Energy Market Conclusion

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2025.

Table 1-2 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on 94.1 percent of the days in the first nine months of 2025. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first nine months of 2025 was, on average, unconcentrated by FERC HHI standards. The average HHI was 686 with a minimum of 511 and a maximum of 988. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was unconcentrated on average. The peaking segment of the supply curve was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. Transmission constraints create the potential for the exercise of local market power. The goal of PJM's application of the three pivotal supplier test is to identify local market power and offer cap to competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in price formation, undermine market efficiency in the energy market. The implementation of fast start pricing on September 1, 2021, undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.[11] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[12] In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market

11 OATT Attachment M (PJM Market Monitoring Plan).
12 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).

performance test to determine if such generator offers would affect the market price.[13] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed, but, so far, PJM and FERC have failed to address them.[14] [15] [16] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

Capacity Market Conclusion

The Market Monitoring Unit (MMU) analyzed market design, market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[17] The conclusions are a result of the MMU's evaluation of the 2026/2027 Base Residual Auction.[18] [19] [20] [21] [22] [23] [24] [25]

Table 1-3 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[26] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[27]
- Participant behavior was evaluated as not competitive in the 2026/2027 BRA. Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity

13 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
14 175 FERC ¶ 61,231 (2021).
15 185 FERC ¶ 61,158 (2023).
16 189 FERC ¶ 61,060 (2024).

17 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
18 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>.
19 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf>.
20 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf>.
21 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part D," (December 6, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf>.
22 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part E," (January 31, 2025). <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_E_20250131.pdf>.
23 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part F," (February 4, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_F_20250204.pdf>.
24 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," (June 3, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf>.
25 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.
26 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. In the 2023/2024 RPM Third Incremental Auction, 36 participants in the RTO passed the TPS test.
27 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.

Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[28] The offers in the 2026/2027 BRA included those based on standalone CPQR offer caps. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.

- Market performance was evaluated as not competitive based on the 2026/2027 Base Residual Auction as a result of the flaws in the Effective Load Carrying Capability (ELCC) design including the failure to correctly define the reliability contribution of thermal resources in the winter, and the failure to recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed.
- Market design was evaluated as mixed because while there are many positive features of the capacity market design and some of the MMU's recommendations were implemented in the 2026/2027 BRA, there are several features of the RPM design which still threaten competitive outcomes. These include the lack of a queue for the addition of large new data center loads, details of PJM's ELCC implementation, the definition of market seller offer caps, the failure to apply the RPM must offer requirement to demand resources, the inclusion of performance assessment interval (PAI) penalties, the use of gross CONE as the maximum price on the VRR curve, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.[29]

28 190 FERC ¶ 61,117 (2025).

29 While PJM filed for and FERC accepted the inclusion of RMR resources Brandon Shores and Wagner plants in the 2026/2027 BRA and 2027/2028 BRA, that does not require that RMR resources be included in capacity market auction clearing in future auctions for these or other RMR resources. See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).

Synchronized Reserve Market Conclusion

- The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first nine months of 2025.

Table 1-4 The synchronized reserve market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The synchronized reserve market structure was evaluated as not competitive due to supplier concentration. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market. The MAD Reserve Subzone was moderately concentrated in the day-ahead market and moderately concentrated in the real-time market.
- Participant behavior was evaluated as competitive because the market rules require all available reserves to offer at cost-based offers.
- Market performance was evaluated as not competitive because the interaction of participant behavior with the market design does not result in competitive prices as a result of PJM's changes to the operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023, raising prices for synchronized reserves, nonsynchronized reserves and energy.
- Market design was evaluated as flawed based on PJM's modifications to the ORDC. PJM previously adopted reforms, including several based on MMU recommendations, removing both physical and economic withholding from the market.
- Significant communications technology issues when calling resources during synchronized reserve events have resulted in slow response from resources. On December 17, 2024, PJM implemented an electronic

deployment of reserves via an augmented dispatch signal, but PJM does not require that resources be able to receive this signal.

Nonsynchronized Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Nonsynchronized Reserve Market for the first nine months of 2025.

Table 1-5 The nonsynchronized reserve market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The nonsynchronized reserve market structure was evaluated as not competitive due to supplier concentration for primary reserve. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market. The MAD Reserve Subzone was moderately concentrated in the day-ahead market and moderately concentrated in the real-time market.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM markets software, so withholding is not possible.
- Market performance was evaluated as not competitive because the interaction of participant behavior with the market design does not result in competitive prices as a result of PJM's changes to the operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023. Because the first step of the ORDC for primary reserve, known as the primary reserve reliability requirement, is based on the synchronized reserve reliability requirement, the primary reserve reliability requirement was consequently also extended, raising prices for synchronized reserves, nonsynchronized reserves, and energy.
- Market design was evaluated as flawed based on PJM's modifications to the first step of the ORDC.

Secondary Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Secondary Reserve Market for the first nine months of 2025.

Table 1-6 The secondary reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The secondary reserve market structure was evaluated as competitive due to the lack of supplier concentration for 30-minute reserve. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM software, so withholding is not possible.
- Market performance was evaluated as competitive because the combination of a competitive market structure and competitive participation resulted in competitive market outcomes.
- The market design was evaluated as effective because the market rules ensure competitive market offers and require repayment of offline cleared secondary reserves that are not available when called on to provide energy in 30 minutes.

Regulation Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first nine months of 2025.

Table 1-7 The regulation market results were not competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 94.2 percent of the hours in the first nine months of 2025.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first nine months of 2025 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin is not consistent with competitive offers.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

FTR Auction Market Conclusion

The *2025 Quarterly State of the Market Report for PJM: January through September* focuses on the 2024/2025 planning period as well as the 2025/2026 Long Term and Annual FTR auctions and ARR allocation, specifically covering June 1, 2024, through September 30, 2025. The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were partially competitive in the first nine months of 2025.

Table 1-8 The FTR auction markets results were partially competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Partially Competitive	
Market Performance	**Partially Competitive**	**Flawed**

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2025/2028 Long Term FTR Auction, the 2025/2026 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions for prevailing flow FTRs. The ownership of FTR obligations is unconcentrated or moderately concentrated for each period of the Monthly Balance of Planning Period Auctions for counter flow FTRs. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and unconcentrated for the 2025/2026 Annual FTR Auction. Ownership of current FTRs is disproportionately (88.7 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs have no option to set an acceptable sale price and are not permitted to participate in the market clearing in any way and are not assured they will receive 100 percent of auction revenues.
- Market performance was evaluated as partially competitive because of the significant and persistent flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.

- Market design was evaluated as flawed because there are significant, fundamental and persistent flaws in the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears and, as a result, sellers are not assured they will receive 100 percent of auction revenues. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. The ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- The fact that load is not able to define its willingness to sell FTRs or to set the prices at which it is willing to sell FTRs and the fact that load is required to return some of the cleared auction revenue to FTR buyers when FTR profits are deemed to be not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Role of MMU

FERC assigns three core functions to MMUs: reporting, monitoring and market design.[30] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[31]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market issues, such as RPM auction reports; reports responding to requests from regulators and other authorities; and ad hoc reports on specific topics. The state of the market reports provide a comprehensive analysis of market structure, participant conduct and market performance for the PJM markets. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU presents reports directly to PJM stakeholders, PJM staff, FERC staff, state commission staff, state commissions, other regulatory agencies and the general public. Report presentations provide an opportunity for interested parties to ask questions, discuss issues, and provide feedback to the MMU.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor,

30 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
31 OATT Attachment M § IV; 18 CFR § 1c.2.

investigate, evaluate and report on the PJM Markets.[32] The MMU has direct, confidential access to FERC.[33] The MMU may also refer matters to the attention of state commissions.[34]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[35] The MMU will investigate and refer "Market Violations," which refer to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[36] [37] [38] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[39]

An important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price-based or cost-based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost-based offer accurately reflects short run marginal cost.

32 OATT Attachment M § IV.
33 OATT Attachment M § IV.K.3.
34 OATT Attachment M § IV.H.
35 OATT § I.1 ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")
36 FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
37 OATT § I.1.
38 The MMU has no prosecutorial or enforcement authority. The MMU notifies FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to FERC, state regulators, stakeholders or other authorities. The MMU may also initiate, participate as a party or provide information or testimony in regulatory or other proceedings.
39 OATT Attachment M § IV.C.

If cost-based offers do not accurately reflect short run marginal cost, the market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. The MMU evaluates every offer cap in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[40]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the day-ahead and real-time energy markets.[41] [42] [43] [44]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns. Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with FERC or other regulatory authorities. FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

The PJM markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[45] [46]

40 OATT Attachment M–Appendix § II.E.
41 OATT Attachment M–Appendix § II.B.
42 OATT Attachment M–Appendix § II.C.
43 OATT Attachment M–Appendix § IV.
44 OATT Attachment M–Appendix § VII.
45 OATT Attachment M–Appendix § II(p).
46 OATT Attachment M–Appendix § III.

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[47]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[48] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[49] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design, market rules and market rule implementation issues, including complaints or petitions.[50] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[51] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[52]

47 OA Schedule 6 § 1.5.
48 OATT Attachment M § IV.D.
49 *Id.*
50 *Id.*; see also, e.g., 171 FERC ¶ 61,039; 167 FERC ¶ 61,084 at PP 70–76, *reh'g denied*, 168 FERC ¶ 61,141.
51 *Id.*
52 OATT Attachment M § VI.A.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[53]

In this *2025 Quarterly State of the Market Report for PJM: January through September*, the MMU includes three new recommendations.

New Recommendations from Section 6, Demand Response

- The MMU recommends that DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 13, Financial Transmission Rights and Auction Revenue Rights

- The MMU recommends that PJM's minimum credit requirements be reviewed and updated to appropriately reflect the risk created for the markets and other market participants. The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollars amounts in 2011 in FERC order 741 based on the specific market participation (FTRs or other). (Priority: Medium. New recommendation. Status: Not adopted.)

53 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

Total Cost of Wholesale Power

The total cost of wholesale power is the average total cost per MWh of wholesale electricity in PJM markets.[54] The costs of each component and subcomponent may vary by location and time period. The total costs are the sum of the total charges for the individual billing line items in each category divided by real time load, even when a specific category is not charged on that basis. The total cost of wholesale power and the components of that cost are presented for informational purposes and should not be used to calculate the costs of any specific market activity in PJM. The total cost includes the cost of energy, capacity, transmission service, ancillary services, and administrative fees billed through PJM systems. Table 1-9 shows the total cost, by component, for the first nine months of 2024 and 2025.

The total costs shown in Table 1-9 equal the total cost per MWh, by category, multiplied by the total real time load. The total costs are different from the total billing values that PJM reports as shown in Figure 1-2. PJM's reported total billing values represent the total dollars (charges) that pass through the PJM settlement process.

Each of the components in Table 1-9 is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's settlement process.[55]

Table 1-9 shows that energy, capacity and transmission charges are the three largest components of the total cost per MWh of wholesale power, comprising 97.9 percent of the total cost per MWh in the first nine months of 2025. The total cost of energy per MWh increased by $15.91 from $32.69 in the first nine months of 2024 to $48.60 in the first nine months of 2025, an increase of 48.7 percent. The total cost of capacity per MWh increased by $7.13 from $3.55 in the first nine months of 2024 to $10.69 in the first nine months of 2025, an increase of 200.8 percent. The total cost of transmission per MWh increased by $0.94 from $17.37 in the first nine months of 2024 to $18.31 in the first nine months of 2025, an increase of 5.4 percent. The total cost per MWh of wholesale power increased by $24.10 from $55.18 in the first nine months of 2024 to $79.28 in the first nine months of 2025, an increase of 43.7 percent.

54 Accounting load is used in the calculation of total price because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, 2007 and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the inclusion of marginal loss pricing in LMP.
55 For more information on the calculation of the total cost of wholesale power, see Monitoring Analytics, "*Total Cost of Wholesale Power Calculation Documentation*," <https://www.monitoringanalytics.com/data/docs/Total_Cost_of_Wholesale_Power_Calculation.pdf>.

Table 1-9 Total cost per MWh by category: January through September, 2024 and 2025[56][57][58]

Category	2024 (Jan-Sep) $/MWh	2024 (Jan-Sep) ($ Millions)	2024 (Jan-Sep) Percent of Total	2025 (Jan-Sep) $/MWh	2025 (Jan-Sep) ($ Millions)	2025 (Jan-Sep) Percent of Total	Percent Change
Energy	$32.69	$19,541	59.2%	$48.60	$29,826	61.3%	48.7%
Day Ahead Energy	$33.47	$20,005	60.6%	$49.31	$30,263	62.2%	47.3%
Balancing Energy	$0.61	$365	1.1%	$1.06	$650	1.3%	73.5%
ARR Credits	($1.23)	($734)	(2.2%)	($1.63)	($1,001)	(2.1%)	32.8%
Self Scheduled FTR Credits	($0.53)	($319)	(1.0%)	($1.29)	($792)	(1.6%)	141.5%
Balancing Congestion	$0.39	$233	0.7%	$0.60	$370	0.8%	54.8%
Emergency Energy	$0.00	$0	0.0%	$0.01	$6	0.0%	0.0%
Inadvertent Energy	$0.02	$9	0.0%	($0.01)	($6)	(0.0%)	(164.4%)
Load Response - Energy	$0.01	$8	0.0%	$0.04	$22	0.0%	172.4%
Emergency Load Response	$0.00	$0	0.0%	$0.06	$36	0.1%	0.0%
Energy Uplift (Operating Reserves)	$0.36	$217	0.7%	$1.07	$660	1.4%	195.8%
Marginal Loss Surplus Allocation	($0.46)	($275)	(0.8%)	($0.71)	($433)	(0.9%)	53.4%
Market to Market Payments	$0.05	$32	0.1%	$0.09	$53	0.1%	57.6%
Capacity	$3.55	$2,124	6.4%	$10.69	$6,560	13.5%	200.8%
Capacity (Capacity Market and FRR)	$3.45	$2,064	6.3%	$10.58	$6,493	13.3%	206.5%
Capacity Part V (RMR)	$0.09	$52	0.2%	$0.08	$48	0.1%	(11.1%)
Load Response - Capacity	$0.01	$8	0.0%	$0.03	$18	0.0%	119.5%
Transmission	$17.37	$10,384	31.5%	$18.31	$11,237	23.1%	5.4%
Transmission Service Charges	$14.74	$8,810	26.7%	$15.54	$9,538	19.6%	5.4%
Transmission Enhancement Cost Recovery	$2.54	$1,518	4.6%	$2.67	$1,641	3.4%	5.3%
Transmission Owner (Schedule 1A)	$0.09	$55	0.2%	$0.10	$58	0.1%	2.9%
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.91	$545	1.7%	$1.03	$630	1.3%	12.7%
Reactive	$0.48	$286	0.9%	$0.45	$274	0.6%	(6.7%)
Regulation	$0.23	$135	0.4%	$0.30	$183	0.4%	31.5%
Black Start	$0.09	$55	0.2%	$0.06	$40	0.1%	(30.1%)
Synchronized Reserves	$0.10	$59	0.2%	$0.19	$118	0.2%	94.0%
Secondary Reserves	$0.00	$2	0.0%	$0.01	$6	0.0%	219.1%
Non-Synchronized Reserves	$0.01	$8	0.0%	$0.02	$11	0.0%	41.4%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Administration	$0.66	$393	1.2%	$0.65	$402	0.8%	(0.5%)
PJM Administrative Fees	$0.61	$364	1.1%	$0.61	$373	0.8%	(0.1%)
NERC/RFC	$0.04	$25	0.1%	$0.04	$26	0.1%	1.0%
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.01	$5	0.0%	$0.00	$3	0.0%	(41.8%)
Total Price	$55.18	$32,987	100.0%	$79.28	$48,655	100.0%	43.7%
Total Day Ahead Load (GWh)	591,116			605,190			2.4%
Total Balancing Load (GWh)	(6,667)			(8,528)			27.9%
Total Real Time Load (GWh)	597,782			613,718			2.7%
Total Cost ($ Billions)	$32.99			$48.65			47.5%

56 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
57 The total cost in this table does not match the PJM reported total billing due to differences in calculation methods. The total prices in this table are load-weighted average system prices per MWh by category, even if each category is not charged on a per MWh basis. PJM's reported total billing represents the total dollars (charges) that pass through the PJM settlement process.
58 The MMU publishes monthly detail of the total cost of wholesale power. See <http://www.monitoringanalytics.com/data/pjm_price.shtml>.

Table 1-10 shows the inflation adjusted average cost, by component, for the first nine months of 2024 and 2025. To calculate the inflation adjusted average costs, the individual components' costs are deflated using the US Consumer Price Index for all items, Urban Consumers (with a base period of January 1998).[59]

Table 1-10 Inflation adjusted total cost per MWh by category: January through September, 2024 and 2025[60 61]

Category	2024 (Jan-Sep) $/MWh	2024 (Jan-Sep) ($ Millions)	2024 (Jan-Sep) Percent of Total	2025 (Jan-Sep) $/MWh	2025 (Jan-Sep) ($ Millions)	2025 (Jan-Sep) Percent of Total	Percent Change
Energy	$16.88	$10,091	59.1%	$24.45	$15,006	60.8%	44.8%
Day Ahead Energy	$17.28	$10,330	60.5%	$24.80	$15,222	61.7%	43.5%
Balancing Energy	$0.31	$188	1.1%	$0.53	$327	1.3%	69.2%
ARR Credits	($0.63)	($379)	(2.2%)	($0.82)	($502)	(2.0%)	29.0%
Self Scheduled FTR Credits	($0.28)	($165)	(1.0%)	($0.65)	($398)	(1.6%)	135.3%
Balancing Congestion	$0.20	$120	0.7%	$0.30	$187	0.8%	51.2%
Emergency Energy	$0.00	$0	0.0%	$0.00	$3	0.0%	0.0%
Inadvertent Energy	$0.01	$5	0.0%	($0.01)	($3)	(0.0%)	(163.0%)
Load Response - Energy	$0.01	$4	0.0%	$0.02	$11	0.0%	164.8%
Emergency Load Response	$0.00	$0	0.0%	$0.03	$18	0.1%	0.0%
Energy Uplift (Operating Reserves)	$0.19	$112	0.7%	$0.54	$334	1.4%	189.5%
Marginal Loss Surplus Allocation	($0.24)	($142)	(0.8%)	($0.36)	($218)	(0.9%)	49.5%
Market to Market Payments	$0.03	$17	0.1%	$0.04	$27	0.1%	54.3%
Capacity	$1.93	$1,153	6.7%	$5.69	$3,491	14.2%	194.9%
Capacity (Capacity Market and FRR)	$1.88	$1,122	6.6%	$5.63	$3,458	14.0%	200.2%
Capacity Part V (RMR)	$0.05	$27	0.2%	$0.04	$24	0.1%	(13.3%)
Load Response - Capacity	$0.01	$4	0.0%	$0.01	$9	0.0%	113.3%
Transmission	$8.97	$5,360	31.4%	$9.20	$5,649	22.9%	2.6%
Transmission Service Charges	$7.61	$4,548	26.6%	$7.81	$4,794	19.4%	2.7%
Transmission Enhancement Cost Recovery	$1.31	$784	4.6%	$1.34	$825	3.3%	2.5%
Transmission Owner (Schedule 1A)	$0.05	$29	0.2%	$0.05	$29	0.1%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.47	$281	1.6%	$0.52	$317	1.3%	9.8%
Reactive	$0.25	$148	0.9%	$0.22	$138	0.6%	(9.2%)
Regulation	$0.12	$70	0.4%	$0.15	$92	0.4%	28.1%
Black Start	$0.05	$28	0.2%	$0.03	$20	0.1%	(31.8%)
Synchronized Reserves	$0.05	$30	0.2%	$0.10	$59	0.2%	89.0%
Secondary Reserves	$0.00	$1	0.0%	$0.00	$3	0.0%	209.8%
Non-Synchronized Reserves	$0.01	$4	0.0%	$0.01	$6	0.0%	38.0%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Administration	$0.34	$203	1.2%	$0.33	$202	0.8%	(3.1%)
PJM Administrative Fees	$0.31	$188	1.1%	$0.31	$188	0.8%	(2.7%)
NERC/RFC	$0.02	$13	0.1%	$0.02	$13	0.1%	(1.7%)
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.00	$2	0.0%	$0.00	$1	0.0%	(43.4%)
Total Price	$28.59	$17,089	100.0%	$40.19	$24,665	100.0%	40.6%
Total Day Ahead Load (GWh)	591,116			605,190			2.4%
Total Balancing Load (GWh)	(6,667)			(8,528)			27.9%
Total Real Time Load (GWh)	597,782			613,718			2.7%
Total Cost ($ Billions)	$17.09			$24.66			44.3%

59 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 24, 2025).
60 The totals in the Transmission section of this table include corrections to previously reported totals which did not include a full accounting of Transmission Enhancement Cost Recovery costs.
61 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-3 shows the total cost of wholesale power in the first nine months of 2024 and 2025.

Figure 1-3 Total cost per MWh by category: January through September, 2024 and 2025

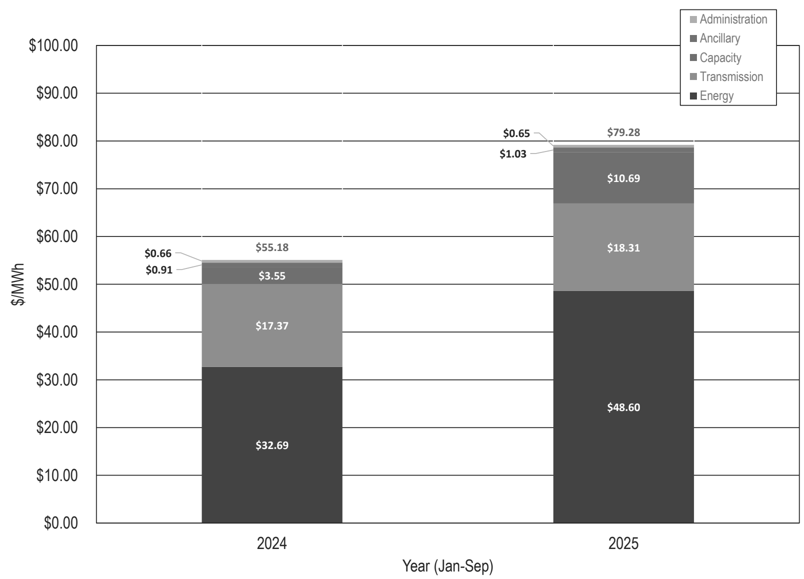
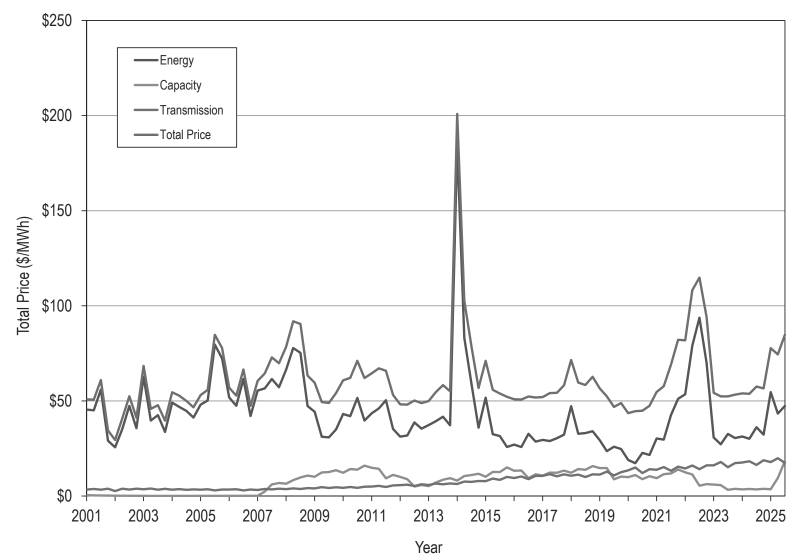


Figure 1-4 shows the contributions of the energy, capacity and transmission service components of the total cost of wholesale power for each quarter since 2001. In the third quarter of 2019, the cost of transmission per MWh of wholesale power exceeded the cost of capacity for the first time. In the third quarter of 2025, significant increases in capacity market prices resulted in the cost of capacity per MWh of wholesale power increasing above the cost of transmission.

Figure 1-4 Top three components of quarterly total cost ($/MWh): January 2001 through September 2025[62]



62 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-11 shows the total cost, by component of the total wholesale power cost per MWh, for calendar years 2001 through 2024.

Table 1-11 Total cost per MWh by category: 2001 through 2024[63]

Category	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/MWh	2019 $/MWh	2020 $/MWh	2021 $/MWh	2022 $/MWh	2023 $/MWh	2024 $/MWh
Energy	$44.41	$36.91	$44.97	$44.95	$63.89	$51.15	$57.76	$66.84	$35.47	$44.36	$44.06	$34.43	$38.94	$93.20	$35.96	$28.74	$30.29	$36.84	$25.99	$20.26	$38.44	$74.42	$30.40	$32.59
Day Ahead Energy	$39.66	$35.34	$41.72	$40.75	$60.21	$50.02	$57.04	$68.59	$37.78	$45.19	$44.29	$33.67	$37.88	$51.81	$36.52	$29.48	$30.92	$37.57	$27.15	$21.09	$38.65	$74.25	$31.58	$33.43
Balancing Energy	$4.46	$2.24	$3.49	$4.06	$3.85	$2.50	$3.05	$3.48	$1.80	$3.56	$2.06	$1.55	$1.83	$42.24	$0.81	$0.53	$0.34	$0.74	$0.17	$0.36	$0.80	$2.04	$0.45	$0.57
ARR Credits	$0.00	$0.00	($0.27)	($0.40)	($0.39)	($0.59)	($0.62)	($0.72)	($0.89)	($0.52)	($0.64)	($0.55)	($0.45)	($0.54)	($0.73)	($0.82)	($0.68)	($0.70)	($0.87)	($0.69)	($0.56)	($1.15)	($1.46)	($1.24)
Self Scheduled FTR Credits	($0.93)	($1.35)	($0.83)	($0.32)	($0.80)	($1.21)	($1.58)	($2.18)	($0.69)	($1.26)	($0.57)	($0.22)	($0.23)	($0.63)	($0.46)	($0.29)	($0.20)	($0.34)	($0.14)	($0.19)	($0.33)	($1.11)	($0.42)	($0.52)
Balancing Congestion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.09	$0.17	$0.18	$0.30	$0.67	$0.39	$0.39
Emergency Energy	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00
Inadvertent Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($0.00)	($0.01)	$0.00	($0.02)	$0.04	$0.01	($0.01)	($0.01)	$0.00	($0.01)	$0.01	$0.01	($0.00)	$0.00	$0.00	($0.03)	$0.01	$0.01
Load Response - Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.00	$0.00	$0.00	$0.01	$0.01	$0.02	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.06	$0.06	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.08	$0.00
Energy Uplift (Operating Reserves)	$1.26	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80	$0.78	$0.74	$0.55	$1.11	$0.38	$0.17	$0.14	$0.23	$0.11	$0.12	$0.23	$0.36	$0.21	$0.34
Marginal Loss Surplus Allocation	($0.05)	($0.04)	($0.05)	($0.09)	($0.10)	($0.07)	($0.86)	($3.07)	($3.06)	($3.47)	($2.03)	($0.86)	($0.73)	($0.93)	($0.63)	($0.37)	($0.35)	($0.88)	($0.65)	($0.68)	($0.70)	($0.87)	($0.51)	($0.45)
Market to Market Payments	$0.00	$0.00	$0.00	$0.00	$0.03	($0.00)	$0.02	$0.06	$0.05	$0.05	$0.10	$0.06	$0.03	$0.06	$0.05	$0.05	$0.07	$0.12	$0.05	$0.06	$0.04	$0.23	$0.07	$0.05
Capacity	$0.27	$0.12	$0.08	$0.09	$0.04	$0.11	$3.85	$8.83	$12.13	$14.04	$12.26	$7.36	$7.58	$10.29	$12.50	$11.78	$12.16	$13.95	$12.00	$9.99	$11.64	$8.81	$4.63	$3.61
Capacity (Capacity Market and FRR)	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.80	$8.79	$12.12	$14.01	$12.12	$7.27	$7.52	$10.25	$12.50	$11.78	$12.12	$13.90	$11.98	$9.99	$11.64	$8.74	$4.53	$3.56
Capacity Part V (RMR)	$0.00	$0.00	$0.00	$0.00	$0.02	$0.08	$0.05	$0.04	$0.01	$0.02	$0.13	$0.08	$0.06	$0.04	($0.00)	($0.00)	$0.04	$0.05	$0.02	$0.00	$0.00	$0.07	$0.11	$0.04
Load Response - Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01
Transmission	$3.56	$3.46	$3.64	$3.43	$3.30	$3.34	$3.55	$3.84	$4.36	$4.54	$5.15	$5.77	$6.29	$7.30	$8.81	$9.75	$10.92	$10.83	$11.79	$13.58	$14.37	$15.12	$16.54	$17.71
Transmission Service Charges	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04	$4.49	$4.90	$5.21	$5.96	$7.09	$7.81	$8.83	$8.81	$9.80	$11.33	$12.00	$12.77	$14.13	$15.04
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.07	$0.25	$0.40	$0.56	$0.78	$0.99	$1.25	$1.62	$1.86	$2.02	$1.92	$1.91	$2.15	$2.29	$2.28	$2.32	$2.58
Transmission Owner (Schedule 1A)	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.05	$0.50	$0.07	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.03)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	($0.01)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.75	$0.63	$0.91	$0.91	$1.19	$0.92	$1.00	$1.15	$0.78	$0.90	$0.90	$0.84	$1.24	$0.99	$0.91	$0.71	$0.76	$0.79	$0.71	$0.72	$0.86	$1.08	$0.89	$0.92
Reactive	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45	$0.41	$0.46	$0.76	$0.40	$0.37	$0.38	$0.42	$0.40	$0.43	$0.47	$0.48	$0.50	$0.52	$0.48
Regulation	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36	$0.32	$0.26	$0.25	$0.33	$0.23	$0.11	$0.14	$0.18	$0.12	$0.10	$0.19	$0.38	$0.17	$0.23
Black Start	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.04	$0.14	$0.08	$0.08	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09	$0.09	$0.09
Synchronized Reserves	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07	$0.09	$0.04	$0.04	$0.12	$0.11	$0.05	$0.06	$0.06	$0.04	$0.03	$0.07	$0.11	$0.10	$0.10
Secondary Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.01	$0.02	$0.02	$0.01	$0.02	($0.01)	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.05	$0.05	$0.06	$0.05	$0.10	$0.07	$0.05	$0.05	$0.02	$0.02	$0.01	$0.01	$0.00	$0.00
Administration	$0.74	$0.86	$1.09	$1.07	$0.77	$0.81	$0.83	$0.48	$0.35	$0.43	$0.40	$0.50	$0.44	$0.47	$0.47	$0.48	$0.53	$0.61	$0.61	$0.55	$0.55	$0.55	$0.62	$0.68
PJM Administrative Fees	$0.73	$0.86	$1.05	$0.93	$0.72	$0.74	$0.76	$0.43	$0.31	$0.36	$0.37	$0.46	$0.40	$0.43	$0.43	$0.44	$0.49	$0.57	$0.57	$0.50	$0.50	$0.50	$0.57	$0.63
NERC/RFC	$0.01	$0.01	$0.04	$0.07	$0.04	$0.05	$0.06	$0.04	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.06	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.03	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.01	$0.01
Total Price	$49.73	$41.98	$50.69	$50.44	$69.19	$56.32	$66.98	$81.14	$53.10	$64.26	$62.76	$48.90	$54.49	$112.24	$58.65	$51.46	$54.66	$63.02	$51.10	$45.10	$65.87	$99.97	$53.08	$55.51
Total Day Ahead Load (GWh)	292,717	344,235	324,653	413,294	654,505	672,501	691,547	676,030	644,485	656,928	704,581	745,165	753,865	749,927	773,842	774,730	760,624	784,553	771,055	734,641	755,824	765,499	748,619	775,838
Total Balancing Load (GWh)	27,319	31,337	(2,879)	(25,580)	(30,087)	(23,664)	(23,977)	(22,429)	(21,584)	(40,463)	(18,519)	(19,136)	(19,925)	(30,578)	(2,251)	(3,538)	1,849	(6,542)	(874)	(8,346)	(11,602)	(13,126)	(6,433)	(8,344)
Total Real Time Load (GWh)	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094	771,929	742,987	767,425	778,624	755,053	784,182
Total Cost ($ Billions)	$13.20	$13.14	$16.60	$22.14	$47.37	$39.21	$47.93	$56.67	$35.37	$44.81	$45.38	$37.37	$42.17	$87.60	$45.52	$40.05	$41.47	$49.86	$39.45	$33.51	$50.55	$77.84	$40.08	$43.53

63 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-12 shows the percent of total cost, by component of the wholesale power cost per MWh, for calendar years 2001 through 2024.

Table 1-12 Percent of total cost per MWh by category: 2001 through 2024[64]

Category	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012
Energy	89.3%	87.9%	88.7%	89.1%	92.3%	90.8%	86.2%	82.4%	66.8%	69.0%	70.2%	70.4%
Day Ahead Energy	79.8%	84.2%	82.3%	80.8%	87.0%	88.8%	85.2%	84.5%	71.1%	70.3%	70.6%	68.9%
Balancing Energy	9.0%	5.3%	6.9%	8.1%	5.6%	4.4%	4.6%	4.3%	3.4%	5.5%	3.3%	3.2%
ARR Credits	0.0%	0.0%	(0.5%)	(0.8%)	(0.6%)	(1.0%)	(0.9%)	(0.9%)	(1.7%)	(0.8%)	(1.0%)	(1.1%)
Self Scheduled FTR Credits	(1.9%)	(3.2%)	(1.6%)	(0.6%)	(1.2%)	(2.1%)	(2.4%)	(2.7%)	(1.3%)	(2.0%)	(0.9%)	(0.5%)
Balancing Congestion	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Inadvertent Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	(0.0%)	0.0%	(0.0%)	0.1%	0.0%
Load Response - Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Energy Uplift (Operating Reserves)	2.5%	1.7%	1.8%	1.9%	1.5%	0.8%	1.0%	0.8%	0.9%	1.2%	1.2%	1.5%
Marginal Loss Surplus Allocation	(0.1%)	(0.1%)	(0.1%)	(0.2%)	(0.1%)	(0.1%)	(1.3%)	(3.8%)	(5.8%)	(5.4%)	(3.2%)	(1.7%)
Market to Market Payments	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.1%	0.1%	0.1%	0.2%	0.1%
Capacity	0.5%	0.3%	0.2%	0.2%	0.1%	0.2%	5.8%	10.9%	22.8%	21.8%	19.5%	15.1%
Capacity (Capacity Market and FRR)	0.5%	0.3%	0.2%	0.2%	0.0%	0.0%	5.7%	10.8%	22.8%	21.8%	19.3%	14.9%
Capacity Part V (RMR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.2%	0.2%
Load Response - Capacity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission	7.2%	8.2%	7.2%	6.8%	4.8%	5.9%	5.3%	4.7%	8.2%	7.1%	8.2%	11.8%
Transmission Service Charges	7.0%	8.1%	7.0%	6.5%	3.9%	5.7%	5.2%	4.5%	7.6%	6.3%	7.2%	10.0%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.5%	0.6%	0.9%	1.6%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.1%	0.2%	0.1%	0.2%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.1%	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.5%	1.5%	1.8%	1.8%	1.7%	1.6%	1.5%	1.4%	1.5%	1.4%	1.4%	1.7%
Reactive	0.4%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.7%	0.9%
Regulation	1.1%	1.0%	1.0%	1.0%	1.2%	0.9%	0.9%	0.9%	0.6%	0.6%	0.5%	0.5%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Synchronized Reserves	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Secondary Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
Administration	1.5%	2.1%	2.1%	2.1%	1.1%	1.4%	1.2%	0.6%	0.7%	0.7%	0.6%	1.0%
PJM Administrative Fees	1.5%	2.0%	2.1%	1.8%	1.0%	1.3%	1.1%	0.5%	0.6%	0.6%	0.6%	0.9%
NERC/RFC	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Category	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016	Percent of Total Charges 2017	Percent of Total Charges 2018	Percent of Total Charges 2019	Percent of Total Charges 2020	Percent of Total Charges 2021	Percent of Total Charges 2022	Percent of Total Charges 2023	Percent of Total Charges 2024
Energy	71.5%	83.0%	61.3%	55.8%	55.4%	58.5%	50.8%	44.9%	58.4%	74.4%	57.3%	58.7%
Day Ahead Energy	69.5%	46.2%	62.3%	57.3%	56.6%	59.6%	53.1%	46.8%	58.7%	74.3%	59.5%	60.2%
Balancing Energy	3.4%	37.6%	1.4%	1.0%	0.6%	1.2%	0.3%	0.8%	1.2%	2.0%	0.8%	1.0%
ARR Credits	(0.8%)	(0.5%)	(1.3%)	(1.6%)	(1.2%)	(1.1%)	(1.7%)	(1.5%)	(0.8%)	(1.2%)	(2.8%)	(2.2%)
Self Scheduled FTR Credits	(0.4%)	(0.6%)	(0.8%)	(0.6%)	(0.4%)	(0.5%)	(0.3%)	(0.4%)	(0.5%)	(1.1%)	(0.8%)	(0.9%)
Balancing Congestion	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.3%	0.4%	0.5%	0.7%	0.7%	0.7%
Emergency Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Inadvertent Energy	(0.0%)	(0.0%)	0.0%	(0.0%)	0.0%	0.0%	(0.0%)	0.0%	0.0%	(0.0%)	0.0%	0.0%
Load Response - Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
Energy Uplift (Operating Reserves)	1.0%	1.0%	0.7%	0.3%	0.3%	0.4%	0.2%	0.3%	0.3%	0.4%	0.4%	0.6%
Marginal Loss Surplus Allocation	(1.3%)	(0.8%)	(1.1%)	(0.7%)	(0.6%)	(1.4%)	(1.3%)	(1.5%)	(1.1%)	(0.9%)	(1.0%)	(0.8%)
Market to Market Payments	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%
Capacity	13.9%	9.2%	21.3%	22.9%	22.2%	22.1%	23.5%	22.1%	17.7%	8.8%	8.7%	6.5%
Capacity (Capacity Market and FRR)	13.8%	9.1%	21.3%	22.9%	22.2%	22.1%	23.4%	22.1%	17.7%	8.7%	8.5%	6.4%
Capacity Part V (RMR)	0.1%	0.0%	(0.0%)	(0.0%)	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.2%	0.1%
Load Response - Capacity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission	11.5%	6.5%	15.0%	18.9%	20.0%	17.2%	23.1%	30.1%	21.8%	15.1%	31.2%	31.9%
Transmission Service Charges	9.6%	5.3%	12.1%	15.2%	16.2%	14.0%	19.2%	25.1%	18.2%	12.8%	26.6%	27.1%
Transmission Enhancement Cost Recovery	1.8%	1.1%	2.8%	3.6%	3.7%	3.1%	3.7%	4.8%	3.5%	2.3%	4.4%	4.6%
Transmission Owner (Schedule 1A)	0.2%	0.1%	0.2%	0.2%	0.2%	0.1%	0.2%	0.2%	0.1%	0.1%	0.2%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	2.3%	0.9%	1.6%	1.4%	1.4%	1.3%	1.4%	1.6%	1.3%	1.1%	1.7%	1.7%
Reactive	1.4%	0.4%	0.6%	0.7%	0.8%	0.6%	0.8%	1.0%	0.7%	0.5%	1.0%	0.9%
Regulation	0.5%	0.3%	0.4%	0.2%	0.3%	0.3%	0.2%	0.2%	0.3%	0.4%	0.3%	0.4%
Black Start	0.3%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%	0.1%	0.1%	0.2%	0.2%
Synchronized Reserves	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%
Secondary Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.0%)	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.1%	0.0%	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Administration	0.8%	0.4%	0.8%	0.9%	1.0%	1.0%	1.2%	1.2%	0.8%	0.5%	1.2%	1.2%
PJM Administrative Fees	0.7%	0.4%	0.7%	0.9%	0.9%	0.9%	1.1%	1.1%	0.8%	0.5%	1.1%	1.1%
NERC/RFC	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

64 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

- **Supply.** In the first nine months of 2025, 2,756 MW of new resources were added in the energy market, and 982 MW of resources were retired.
- The real-time hourly on peak average offered supply in the first nine months of 2025 increased by 1.4 percent, from the first nine months of 2024, from 140,934 MWh to 142,851 MWh.
- The day-ahead hourly average offered supply in the first nine months of 2025 decreased by 1.5 percent, from the first nine months of 2024, from 153,603 MWh to 151,275 MWh.
- The real-time hourly average cleared generation in the first nine months of 2025 increased by 3.3 percent from the first nine months of 2024, from 96,954 MWh to 100,136 MWh.
- The day-ahead hourly average cleared supply in the first nine months of 2025, including INCs and UTCs, increased by 1.9 percent from the first nine months of 2024 from 112,192 MWh to 114,328 MWh.
- **Demand.** The real-time hourly peak load without exports in the first nine months of 2025 was 156,256 MWh (158,789 MWh with net exports) in the HE 1800 (EPT) on June 23, 2025, higher than the PJM peak load in the first nine months of 2024, which was 144,245 MWh (149,398 MWh with net exports) in the HE 1800 (EPT) on June 21, 2024.
- The real-time hourly average load in the first nine months of 2025 increased by 3.0 percent from the first nine months of 2024, from 90,917 MWh to 93,683 MWh.
- The day-ahead hourly average cleared demand in the first nine months of 2025, including DECs and UTCs, increased by 1.4 percent from the first nine months of 2024, from 106,355 MWh to 107,864 MWh.

Market Behavior

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 4.6 percent and the cleared increment MW increased by 8.4 percent in the first nine months of 2025 compared to the first nine months of 2024. The hourly average submitted decrement bid MW increased by 17.7 percent and the cleared decrement MW decreased by 2.6 percent in the first nine months of 2025 compared to the first nine months of 2024. The hourly average submitted up to congestion bid MW decreased by 2.1 percent and the cleared up to congestion bid MW decreased by 8.2 percent in the first nine months of 2025 compared to the first nine months of 2024.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2025, generation from coal units increased 16.1 percent, generation from natural gas units decreased 1.6 percent, generation from oil units increased 25.8 percent, generation from wind units increased 1.8 percent, and generation from solar units increased 46.4 percent compared to the first nine months of 2024.
- **Fuel Diversity.** The fuel diversity of energy generation in the first nine months of 2025, measured by the fuel diversity index for energy (FDI_e), increased 2.5 percent compared to the first nine months of 2024.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first nine months of 2025, coal units were 7.6 percent, natural gas units were 77.9 percent and wind units were 10.3 percent of marginal resources. In the first nine months of 2024, coal units were 11.0 percent, natural gas units were 74.8 and wind units were 11.9 percent of marginal resources.
- **Prices.** The real-time load-weighted average LMP in the first nine months of 2025 increased $16.20 per MWh, or 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh.

- The day-ahead load-weighted average LMP for the first nine months of 2025 increased $16.03 or 47.4 percent from the first nine months of 2024, from $33.85 per MWh to $49.88 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was $50.51 per MWh for the first nine months of 2025, which is 9.0 percent, $4.17 per MWh, higher than the real-time load-weighted average DLMP of $46.34 per MWh.
- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in the first nine months of 2025, 7.2 percent of the real-time load-weighted LMP was the result of coal costs, 43.4 percent was the result of gas costs, 4.3 percent was the result of the cost of emission allowances, and 10.5 percent was the result of transmission constraint violation penalty factors.
- **Components of Day-Ahead LMP.** In the PJM Day-Ahead Energy Market in the six months between April and September of 2025, 7.2 percent of the day-ahead load-weighted LMP was the result of coal costs, 12.2 percent was the result of gas costs, 33.2 percent was the result of the decrement bids, and 18.5 percent was the result of increment offers.
- **Changes in Real-Time LMP.** Of the $16.20 per MWh increase in the real-time load-weighted average LMP, $9.85 per MWh (60.8 percent) was the fuel and consumables cost components of LMP, -$0.16 per MWh (-1.0 percent) was the emissions cost components of LMP, $0.85 per MWh (5.2 percent) was the sum of the markup, maintenance, and ten percent adder components of LMP, $2.07 per MWh (12.8 percent) was the transmission constraint penalty factor component of LMP, and $1.14 per MWh (7.0 percent) was the scarcity component of LMP. The pre-emergency demand response called on by PJM during the hot weather days in June and July increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.11 per MWh, a 0.7 percent decrease.
- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The average difference between day-ahead and real-time average prices was $0.38 per MWh in the first nine months of 2025, and $0.41 per MWh in the first nine months of 2024. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- **Shortage Intervals.** There were 130 intervals with five minute shortage pricing on 22 days in the first nine months of 2025. Of the 130 intervals, 79 occurred during the June 2025 heatwave, for which PJM issued several emergency warnings and actions. Seven of the 130 intervals of shortage overlapped with synchronized reserve events.
- **SCED Shortage Intervals.** In the first nine months of 2025, there were 4,082 five minute intervals, or 5.2 percent of all five minute intervals, for which at least one RT SCED solution showed a shortage of reserves. In the first nine months of 2025, there were 1,368 five minute intervals, or 1.7 percent of all five minute intervals, for which more than one RT SCED solution showed a shortage of reserves. In the first nine months of 2025, PJM triggered shortage pricing for 130 five minute intervals, or 0.2 percent of all five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Three suppliers were jointly pivotal in the day-ahead market on 257 days, 94.1 percent of the days, in the first nine months of 2025 and 138 days, 50.4 percent of the days, in the first nine months of 2024.
- **Local Market Power.** In the first nine months of 2025, in the real-time market, the 500 kV system, 13 zones, and the PJM/MISO interface experienced congestion resulting from one or more constraints binding for 75 or more hours. For seven out of the top 10 congested facilities (by

real-time binding hours) in the first nine months of 2025, the average number of suppliers providing constraint relief was three or fewer. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 2.0 percent in the first nine months of 2024 to 1.9 percent in the first nine months of 2025. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.5 percent in the first nine months of 2024 to 1.4 percent in the first nine months of 2025. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.

  The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.18 percent in the first nine months of 2024 to 0.10 percent in the first nine months of 2025. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.23 percent in the first nine months of 2024 to 0.12 percent in the first nine months of 2025. The low offer cap percentages for reliability commitments, relative to offer capping for transmission constraints, do not mean that units committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated consistent with that fact.

- **Parameter Mitigation.** PJM applies operating parameter limits (PLS) to units that fail the TPS test and to all units during hot and cold weather alerts. In the first nine months of 2025, 29.3 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. On days when cold weather alerts and hot weather alerts were declared, 31.2 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first nine months of 2025, no units qualified for an FMU adder. In 2024, 2023 and 2022, no units qualified for an FMU adder. In 2021, one unit qualified for an FMU adder.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -$0.07 when using unadjusted cost-based offers in the first nine months of 2025, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first nine months of 2025 was more than $900 per MWh and the highest markup in the first nine months of 2024 was more than $900 per MWh, using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was $0.23 per MWh in the six months between April and September of 2025, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the six months between April and September of 2025 was more than $550 per MWh.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup frequency distributions also show that a significant proportion of units were offered with high markups, consistent with the exercise of market power.

Market Performance

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

  In the PJM Real-Time Energy Market in the first nine months of 2025, the unadjusted markup component (net of positive and negative markup components) of LMP was -$0.09 per MWh or -0.2 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $2.74 per MWh, or 3.5 percent of the real-time peak hour load-weighted average LMP for July.

  In the PJM Day-Ahead Energy Market in the six months between April and September of 2025, the unadjusted markup component (net of positive and negative markup components) of LMP was $2.64 per MWh or 12.2 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $7.59 per MWh, or 8.59 percent of the day-ahead peak hour load-weighted average LMP for July.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 3.0 percent of all real-time marginal unit intervals in the first nine months of 2025, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.

- **Markup and Aggregate Market Power.** In the first nine months of 2025, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $100 per MWh on 117 days, compared to 76 days in the first nine months of 2024.[65] Some of the marginal units had local market power, but were not offer capped due to issues with the method that PJM uses to select offer schedules for units that fail the TPS test. Some of the marginal units had aggregate market power, for which there is no offer capping, and some had both local and aggregate market power.

Section 3 Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers per the PJM Operating Agreement not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short

65 The number of days reported in the 2025 Quarterly State of the Market Report for PJM: January through March and the 2025 Quarterly State of the Market Report for PJM: January through June were understated, and have been correctly calculated in this 2025 Quarterly State of the Market Report for PJM: January through September.

run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Partially adopted 2023.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Partially adopted.)
- The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)[66]
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior

66 The real-time market formula for determining the lowest cost schedule is documented. The day-ahead market formula for determining the lowest cost schedule is not documented.

time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, that PJM commit all resources that fail the TPS test on their cost-based offers, that the Market Seller designate the cost-based offer if there is more than one, and that PJM implement this solution as soon as possible. (Priority: High. First reported Q3 2024. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)[67]

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage resources be subject to an enforceable ICAP must offer rule in the day-ahead and real-time energy markets that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, that gas generators be required to inform PJM about whether they have gas, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported 2022. Status: Not adopted.)

67 The applicability of the FMU and AU adders is limited by the rule implemented in 2014 requiring that net revenues must fall below avoidable costs, but the possibility of FMU and AU adders is still part of the PJM Market Rules.

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[68]
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported 2022. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[69]
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission

68 Flexible parameter standards are in place for combined cycle and combustion turbine resources when operating on a parameter limited schedule, but not for other schedules or generating technologies.

69 PJM created a more transparent process for transmission constraint penalty factors and added it to the tariff in 2020. Policies on reductions in control limits and the duration of violations remain discretionary and undocumented in the PJM Market Rules.

system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.[70] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[71] [72] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and LPC and instead limit the sum of violated reserve constraint shadow prices that are included in the determination of LMP in LPC to $1,700 per MWh. While PJM no longer caps prices in RT SCED, PJM continues to apply a cap to the system marginal price in the pricing

70 This recommendation was the result of load shed events in September, 2013. For detailed discussion, please see *2013 Annual State of the Market Report for PJM*, Volume 2: Section 3 at 114 – 116.
71 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.
72 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

run (LPC) under fast start pricing. (Priority: Medium. First reported 2021. Status: Not adopted.)

- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. First reported 2021. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[73]
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[74]

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

73 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.
74 The PJM Market Rules clarify that shortage case approval will be based on RT SCED, but does not address RT SCED case choice or load bias.

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2025, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market. In a competitive market, prices are directly related to input prices, the marginal cost to serve load. In the first nine months of 2025, LMP increased by $16.20 per MWh compared to the first nine months of 2024. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased $9.85 per MWh, 60.8 percent of the increase in LMP. The emissions cost components of LMP, including opportunity costs for emissions limited resources, decreased by $0.16 per MWh, -1.0 percent of the increase in LMP. The transmission constraint penalty factor component increased by $2.07 per MWh, 12.8 percent of the increase in LMP, primarily as a result of PJM actions to reduce the line limits applied in SCED (control limits) below the actual line limits. The pre-emergency demand response called on by PJM during the hot weather days in June and July increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.11 per MWh, a 0.7 percent decrease.

The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first nine months of 2025 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first nine months of 2025, the sum of the markup, ten percent adder, and maintenance cost (not short run marginal cost) components increased by $0.85 per MWh or 5.2 percent of the increase in LMP. In addition, PJM actions in the form of transmission constraint penalty factors, significantly increased prices.

The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to be addressed.[75] There also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels. For example, PJM approved 21.9 percent of solved shortage cases in June 2025, but only 3.2 percent for the first nine months of 2025. Six of the other eight months had a higher percent of shortage cases solved, but fewer approved. The pattern of shortage case approvals indicates that PJM considers factors that are not documented in the tariff when deciding whether to approve shortage cases. The application of shortage pricing should not involve operator discretion. As directed by FERC Order No. 825, PJM should approve shortage cases based on market software results alone.[76]

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised and to ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing for revenue adequacy, as in PJM's 2019 ORDC proposal that would have created administrative scarcity pricing, is not consistent with a competitive market design. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is consistent with a competitive market design. Scarcity pricing is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, that scarcity pricing not be excessive or punitive, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

PJM defined inputs to the dispatch tools, particularly RT SCED, have substantial effects on energy market outcomes. Transmission line ratings in SCED, transmission constraint penalty factors, load forecast bias, hydro resource schedules, fast start pricing, and the treatment of demand resources change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission constraint penalty factors. PJM operator interventions to reduce the control limits on transmission constraint line ratings in RT SCED unnecessarily trigger transmission constraint penalty factors and significantly increase prices. In the first nine months of 2025, the control limit used in RT SCED for 85 percent of violated transmission constraint intervals was less than 100 percent of the actual line limit, with an average reduction of 5.1 percent. If the control limits had not been artificially reduced for PJM transmission constraints and everything else remained unchanged, the transmission constraint penalty factor's contribution to the load-weighted average LMP in the first nine months of 2025 would have decreased by 99.4 percent from $5.31 to $0.03 per MWh. PJM should evaluate its interventions in the market, including the unnecessary imposition of transmission constraint penalty factors, reconsider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and despite the stated goal of reducing overall uplift, created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[77] The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. Units that start in one hour are not actually fast start units, and their commitment

75 177 FERC ¶ 61,209 (2021).
76 155 FERC ¶ 61,276 at P 161 (2016) ("shortage pricing is required only when a shortage of energy or operating reserves is indicated by the RTO's/ISO's software").
77 See 173 FERC ¶ 61,244 (2020).

costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying uplift in an attempt to counter the distorted incentives inherent in fast start pricing. PJM is also using the pricing run to implement administrative pricing rules that are not related to fast start pricing. Specifically, PJM uses lower transmission constraint penalty factors in the day-ahead pricing run than in the dispatch run and implements system marginal price capping in the pricing run. Every difference between the dispatch run and the pricing run introduces another inefficiency in the market. In the four years since fast start pricing was introduced, the market has not responded with new entry of fast start units despite consistently higher LMPs when a fast start unit sets price.

The energy market requires more flexible operation of the dispatchable fleet as wind and solar resource penetration grows. Since 2018, PJM has argued that the way to incent investment in flexible units is to increase reserve requirements and to increase the administrative prices defined in the ORDCs. In fact, PJM's ORDCs would benefit inflexible units. Providing windfall gains to all generation through higher LMPs during more frequent reserve shortages is not an effective incentive for flexibility.

The question of how to provide market incentives for investment in flexibility, and for operating to the full capability of that flexibility should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? Are units inflexible because the PJM software does not model combined cycle transitions?

A direct solution would include improved modelling of generator capabilities, so that PJM can send more targeted dispatch signals that generators are consistently capable of following. A direct solution would include targeted reforms to PJM software, like multi-interval dispatch and combined cycle modelling would directly address PJM energy market performance. A direct solution would include stronger standards in the PJM Market Rules for performance of resources to their actual physical parameters. These reforms would be more efficient and effective than simply raising prices across the board.

The relationship between supply and demand is referred to as the supply-demand fundamentals, or economic fundamentals, or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes at all times. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market with increasing frequency. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[78] However, there are issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021, but failed to address them in its November 30, 2023 order.[79] [80] Many of these issues can be resolved by simple rule changes. PJM filed and, on October 25, 2024, FERC accepted a proposal that would require that sellers that fail the TPS test will be

78 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
79 See 175 FERC ¶ 61,231 (2021).
80 185 FERC ¶ 61,158 (2023).

offer capped at their cost-based offers and that operating parameters will be mitigated.[81] That order has no current effect because FERC approved the PJM filing that linked, for no logical reason, implementing the improved rules to PJM's adoption of an improved combined cycle model with no defined date. The flawed rules remain in place. There is no reason to delay implementation of the FERC approved rules until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The approved approach should be implemented as soon as possible to help ensure effective market power mitigation.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs in cost-based energy offers that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs. This rule also had unintended consequences for market seller offer caps in the capacity market. Maintenance costs includable in energy offers cannot be included in capacity market offer caps based on avoidable costs. As a result, capacity market offer caps based on net avoidable costs were lower than they would have been if maintenance costs had been correctly included in avoidable costs rather than incorrectly defined to be part of short marginal costs of producing energy and includable in energy offers.

A competitive power market will result in higher prices when fuel costs increase and lower prices when fuel costs decrease. A competitive market will not result in higher prices when markups increase based on market power, or when PJM selects a price-based offer including a markup rather than a cost-based offer in the presence of local market power, or when PJM artificially triggers transmission constraint penalty factors. The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in the first nine months of 2025 or prior years. Given the structure of the energy market which can permit the exercise of aggregate and local market power, some participants' offer behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. In addition, PJM's extensive administrative interventions in the energy market should be reduced. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2025.

81 189 FERC ¶ 61,060 (2024).

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $442.1 million, or 202.3 percent, in the first nine months of 2025 compared to the first nine months of 2024, from $218.5 million to $660.6 million.
- **Types of energy uplift credits.** In the first nine months of 2025, total energy uplift credits included $181.5 million in day-ahead generator credits, $447.7 million in balancing generator credits, $28.9 million in lost opportunity cost credits. Dispatch differential lost opportunity credits, which are a subset of balancing operating reserves, were implemented as part of fast start pricing on September 1, 2021, and were $2.0 million in the first nine months of 2025.
- **Types of units.** In the first nine months of 2025, steam coal units received 9.1 percent of day-ahead generator credits, and combustion turbines received 53.5 percent of balancing generator credits and 64.8 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 36.3 percent of dispatch differential lost opportunity credits, and hydro units received 47.5 percent of dispatch differential lost opportunity credits

- **Concentration of energy uplift credits.** In the first nine months of 2025, the top 10 units receiving energy uplift credits received 37.5 percent of all credits and the top 10 organizations received 70.3 percent of all credits.
- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $3.2 million, or 12.3 percent, in the first nine months of 2025, compared to the first nine months of 2024, from $25.7 million to $28.9 million.

  Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 65.2 percent of the $29.0 million of lost opportunity costs.
- **Following dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $17.9 million, of which PJM has resettled only $3.9 million, or 22.0 percent.

Energy Uplift Charges

- **Energy Uplift Charges.** In the first nine months of 2025, total energy uplift charges increased by $443.1 million, or 203.8 percent, compared to the first nine months of 2024, from $217.4 million to $660.6 million.
- **Types of Energy Uplift Charges.** In the first nine months of 2025, total uplift charges included $181.4 million in day-ahead operating reserve charges, $478.1 million in balancing generator charges, $0.6 million in reactive charges, and $0.4 million in black start services.

Section 4 Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM require wind units to request CIRs based on the maximum output used in the ELCC calculation for wind units. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[82]

Section 4 Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum

82 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market demand (VRR) curve. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result inflates uplift costs, suppresses energy prices, and is an incentive to inflexibility.

It is not appropriate to accept that inflexible units should be paid uplift based on inflexible offers. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules. Such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift. There are defined steps that could and should be taken immediately to improve the modeling of combined cycle plants that do not require investment in combined cycle modeling software, including modeling soak time, and accurately accounting for transition times to power augmentation offer segments.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of fast start pricing. The same is true of PJM's proposals to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs creates a tradeoff between minimizing production costs and reduction of uplift. The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing approach.[83] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units routinely receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[84] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability by PJM in the day-ahead market.

83 Fast start pricing was approved by FERC and implemented on September 1, 2021. See 173 FERC ¶ 61,244 (2020).
84 On June 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280 (2019).

Uplift payments could be significantly reduced by reversing many of the changes that have been made to the original basic uplift rules. The goal of uplift is to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, to operate at a loss. In the original PJM design, uplift was calculated on a daily basis, including all costs and net revenues. But that rule was changed to use only segments of the day. The result is to overstate uplift payments because units may be paid uplift for a day in which their net revenues exceed their costs. In the original PJM design, all net revenues from energy and ancillary services were an offset to uplift payments. That rule was changed to eliminate net revenue from the regulation market. The result is to overstate uplift payments, for no logical reason.

Uplift payments could also be significantly reduced to a more efficient level by eliminating all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing generator credits.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch. PJM continues to pay uplift to units that do not follow dispatch. PJM and the MMU are actively working together to revise the definition of following dispatch to address these issues.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $17.9 million of incorrect uplift credits of which PJM has agreed and resettled only $3.9 million over the last two years, or 22.0 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases and generators offer to repay the credits.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

Polar Vortex 2025 resulted in 51.3 percent of uplift credits in the first nine months of 2025. This level of uplift was consistent with the efficient operation of a reliable market. In anticipation of the cold weather and to avoid a repetition of the poor performance during Winter Storm Elliott, PJM made out of market commitments to mitigate generation performance risks associated with cold temperatures and natural gas commodity illiquidity over the weekend and intraday. PJM took conservative measures to ensure reliability by scheduling resources well in advance of the day-ahead energy market. As there is no multiday market, out of market actions taken before the market starts generally result in uplift. While the results of the Polar Vortex 2025 vindicated PJM's strategy, the rules governing PJM's actions should be more transparent and clearly documented. The results of Polar Vortex 2025 are preferred to Winter Storm Elliott and increased uplift is the expected result. Nonetheless, the uplift rules need significant improvement. In addition, the process of conservative operations and advanced commitments needs to be improved, formalized, and made as market based as possible in order to minimize uplift.

Overview: Section 5, Capacity Market

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a three year forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.[85] PJM introduced the Capacity Performance design for the 2017/2018 BRA. PJM introduced a new ELCC method for defining capacity MW offered in the 2025/2026 BRA.[86]

Under RPM, capacity obligations are annual.[87] By design, Base Residual Auctions (BRA) are held for delivery years that are three years in the future despite recent auction delays. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[88] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year although some incremental auctions have not been held as a result of delays in holding BRAs.[89] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[90] A Reliability Backstop Auction may be conducted if tariff defined criteria are met to resolve reliability criteria violations caused by lack of sufficient capacity procured through RPM auctions.[91] If the installed reserve margin resulting from the total UCAP committed through self supply or BRAs for three consecutive years is more than one percentage point lower than the approved PJM installed reserve margin, PJM will make a filing with FERC to conduct a Reliability Backstop Auction. If the total UCAP committed for all base load generation resources in BRAs for three consecutive years is less than the forecasted minimum hourly load, PJM will make a filing with FERC to conduct a Reliability Backstop Auction.

The 2025/2026 RPM Third Incremental Auction and the 2026/2027 RPM Base Residual Auction were conducted in the first nine months of 2025.

Market Structure

- **RPM Installed Capacity.** In the first nine months of 2025, RPM installed capacity increased 2,072.3 MW or 1.2 percent, from 179,656.2 MW on January 1, to 181,728.5 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** Total reserves on June 1, 2025, were 19,999.9 MW, which is 205.1 MW (UCAP) short of the required reserve level of 20,205.0 MW (UCAP). On June 1, 2025, the target installed reserve margin was 17.8 percent, and the actual reserve margin was only 17.6 percent.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2025, 48.9 percent was gas; 20.7 percent was coal; 17.7 percent was nuclear; 4.5 percent was hydroelectric; 2.2 percent was oil; 1.2 percent was wind; 0.3 percent was solid waste; and 4.4 percent was solar.
- **Market Concentration.** In the 2025/2026 RPM Third Incremental Auction and the 2026/2027 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal

85 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
86 See 186 FERC ¶ 61,080 (2024), *reh'g order*, 189 FERC ¶ 61,043 (2024).
87 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
88 See 126 FERC ¶ 61,275 at P 86 (2009).
89 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
90 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
91 See OATT Attachment DD § 16.

supplier (TPS) test.[92] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[93] [94] [95]

- **Imports and Exports.** Of the 1,281.7 MW of imports offered in the 2026/2027 RPM Base Residual Auction, 1,281.7 MW cleared. Of the cleared imports, 697.4 MW (54.4 percent) were from MISO.
- **Demand Resources.** Committed DR was 5,782.9 MW for June 1, 2025, as a result of cleared capacity for demand resources in RPM auctions for the 2025/2026 Delivery Year (6,265.9 MW) less replacement capacity (483.0 MW).
- **Energy Efficiency Resources.** EE is not a capacity resource but is paid the capacity market clearing price as a subsidy through the 2025/2026 Delivery Year. Committed EE was 1,481.6 MW for June 1, 2025, as a result of MW offered at a price less than or equal to the RPM auction clearing price in RPM auctions for the 2025/2026 Delivery Year (1,493.2 MW) less replacement MW (11.6 MW).

Market Conduct

- **2025/2026 RPM Third Incremental Auction.** Of the 307 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for two generation resources (0.7 percent).
- **2026/2027 RPM Base Residual Auction.** Of the 1,293 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for 82 generation resources (6.3 percent).

92 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).
93 See OATT Attachment DD § 6.5.
94 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
95 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Market Performance

- The 2025/2026 RPM Third Incremental Auction and the 2026/2027 RPM Base Residual Auction were conducted in the first nine months of 2025. The weighted average capacity price for the 2025/2026 Delivery Year is $296.98 per MW-day, including all RPM auctions for the 2025/2026 Delivery Year. The weighted average capacity price for the 2026/2027 Delivery Year is $329.17 per MW-day, including all RPM auctions for the 2026/2027 Delivery Year.
- For the 2025/2026 Delivery Year, RPM annual charges to load are $14.8 billion.
- In the 2026/2027 RPM Base Residual Auction, the market performance was determined to be not competitive.

Part V Reliability Service (RMR)

- Of the nine companies (28 units) that have provided service following deactivation requests, two companies (seven units) filed to be paid under the deactivation avoidable cost rate (DACR), the formula rate. The other seven companies (21 units) filed to be paid under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first nine months of 2025 was 6.6 percent, an increase from 4.5 percent in the first nine months of 2024.[96]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first nine months of 2025 was 83.7 percent, a decrease from 86.3 percent in the first nine months of 2024.

96 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on October 22, 2025. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Section 5 Recommendations[97]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, and imports.[98] [99] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market construct because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 Delivery Year. EE is not a capacity resource as defined in the tariff, and there is no reason to continue to pay large subsidies to EE providers.[100] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[101]
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs to intermittent resources that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[102]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. (Priority: High. First reported 2023. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the

97 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

98 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

99 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

100 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 37 (Dec. 18, 2024).

101 See 189 FERC ¶ 61,095 (2024).

102 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. (Priority: High. First reported Q2, 2025. Status: Not adopted.)

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement in the 2022 Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as 1.5 times Net CONE, capped at Gross CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the gross CONE in ICAP terms for a CT to the gross CONE in UCAP terms be the ELCC based on winter ratings. (Priority: High. First reported 2024. Status: Adopted 2025.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model including transmission constraints inside LDAs. The market design should clear and pay units that are needed for reliability per PJM's transmission reliability analysis in order to forestall RMRs. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system inside and outside LDAs consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)[103]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)

103 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)[104]
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that modifications to existing resources, including relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[105]
- The MMU recommends that the RPM market power mitigation rules be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity for both new resources and existing resources. (Priority: Medium. First reported 2017. Status: Not adopted.)[106]
- The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

104 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

105 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

106 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[107] (Priority: High. First reported 2013. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage and associated performance penalty. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined to reflect seasonal extreme conditions. (Priority: Medium. First reported 2022. Status: Not adopted.)

107 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or subzonal, or defined combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from the current one quarter prior (See Table 5-29) to 12 months prior to an auction in which the unit will not be offered due to deactivation; and no less than 12 months prior to the date of deactivation (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends elimination of both the cost of service recovery rate option and the deactivation avoidable cost rate option for providing Part V reliability service (RMR), and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental

costs required to operate to provide the service plus a defined incentive. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that if units that are paid under Part V of the OATT (RMR) are included in the calculation of CETO and/or reliability in the relevant LDA, the capacity of the RMR resources should also be included in capacity market supply at zero cost, but without all the obligations of a capacity resource, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions, until a decision is made to build transmission as a replacement, and then should be included. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate timely and competitive entry into the PJM markets, open access to the transmission system and maintain the priority order defined by the queue process. (Priority: High. First reported 2023. Status: Not adopted.)

Section 5 Conclusion

The analysis of the PJM Capacity Market begins with market design and market structure, which provide the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market design and market structure. Regardless of the ownership structure of a market, the market design can result in noncompetitive outcomes. In a good market design and a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power like the PJM Capacity Market, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. The analysis also examines the impact of market design choices on market performance.

The MMU concludes that the results of the 2026/2027 RPM Base Residual Auction were significantly affected by flawed market design elements including the lack of a queue for the addition of large new data center loads, by the performance assessment interval (PAI) penalties that are part of the CP design, by PJM's ELCC approach, by the definition of market seller offer caps, by the failure to extend the RPM must offer requirement to demand resources, and by the product definition and lack of market power mitigation for demand resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. PJM filed changes that were approved by FERC and included in the 2026/2027 BRA to adopt two of the MMU's recommendations, the inclusion of specific RMR resources as supply in the next two BRAs and the elimination of the categorical exemption to the RPM must offer requirement for all but demand resources.[108] [109]

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. While the market may be long at times, that is not the equilibrium state. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless, a competitive outcome can be assured by appropriate market power mitigation rules within an effective market design. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or

108 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).
109 190 FERC ¶ 61,117 (2025).

Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules.

The basic conclusion of Part A of the MMU's analysis of the 2026/2027 BRA is that data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA and 2026/2027 BRA or the currently expected tight supply conditions and high prices for subsequent capacity auctions. The combined total increase in capacity market revenues resulting from data center load, both actual and forecast, for the 2025/2026 BRA and the 2026/2027 BRA was $16,603,301,829.[110] [111] This total will continue to grow until the issues associated with the additions of large data center loads are addressed. The impact will increase significantly in the 2028/2029 BRA currently scheduled for June 2026, when the maximum and minimum prices defined by the Agreement are no longer effective.

It is misleading to assert that the capacity market results are simply just a reflection of supply and demand. The current conditions are not the result of organic load growth. The current conditions in the capacity market are almost entirely the result of large load additions from data centers, both actual historical and forecast. The growth in data center load and the expected future growth in data center load are unique and unprecedented and uncertain and require a different approach than simply asserting that it is just supply and demand.

It is equally misleading to assert that the PJM Capacity Market does not work as a result of the impact of existing and forecast large data center load additions. Despite all the issues with PJM's changes to the capacity market design, the PJM Capacity Market would have provided for reliability at prices consistent with organic load growth and the cost of new capacity were it not for the paradigm shift represented by the almost inexhaustible demand for power from data centers.

Data center load growth is the core reliability issue facing PJM markets at present. There is still time to address the issue but failure to do so will result in very high costs for other PJM customers and could also result in a switch from competitive markets to cost of service regulation. Customers are already bearing billions of dollars in higher costs as a direct result of existing and forecast data center load as the Market Monitor demonstrated in Part G of the 2025/2026 BRA Analysis report and Part A of the 2027/2027 BRA Analysis Report.[112] [113]

PJM should not continue to interconnect large new data center load if it cannot be served reliably. The goal should be to serve all load that can be served reliably. The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile

For the first time since the introduction of the RPM capacity market design, the 2026/2027 BRA used a VRR curve with both a defined maximum price and a defined minimum price. The maximum and minimum prices were based on the Agreement between Governor Shapiro of Pennsylvania and PJM that was incorporated in a PJM filing with FERC.[114] That VRR curve with the defined maximum and minimum price is referred to in this report as the restricted VRR curve. The VRR curve that would have been used absent the Agreement is referred in this report as the unrestricted VRR curve.

110 *See*, "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_2025 2026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf> (June 3, 2025).

111 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," ("Part A") <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf> (October 1, 2025).

112 Post Technical Conference Comments of the Independent Market Monitor for PJM (July 7, 2025) *Resource Adequacy Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions*, Docket No. AD25-7.

113 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.

114 On December 30, 2024, in Docket No. EL25-46-000, Governor Josh Shapiro and the Commonwealth of Pennsylvania filed a complaint against PJM asserting that the maximum price for PJM's capacity auctions is unjust and unreasonable. The Governor and PJM reached an Agreement. On February 20, 2025, in Docket No. ER25-1357-000, pursuant to FPA section 205, PJM submitted proposed revisions to its Tariff to establish a specific maximum price and minimum price for all RPM auctions for the 2026/2027 and 2027/2028 delivery years, consistent with the Agreement.

The Agreement resulted in a reduction of BRA revenues of $3,169,915,210, or 16.4 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant. If the 2026/2027 BRA had been run with an unrestricted VRR curve, total revenues would have been $19,294,286,100, an increase of $3,169,915,210, or 19.7 percent, compared to the actual auction revenues of $16,124,370,889 (Scenario 1).

The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The maximum price on the VRR curve has a significant impact on market prices particularly when the market is tight. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The VRR curves used in the 2025/2026 BRA included a maximum price equal to gross CONE for most LDAs that resulted in a significant increase in customer payments for load as a result of paying a price above the competitive level. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power.

For the 2026/2027 RPM Base Residual Auction, total reserves were 21,353.2 MW, which is 208.7 MW (UCAP) short of the required reserve level of 21,561.9 MW (UCAP). The level of committed demand resources in the 2026/2027 BRA was 5,530.6 MW, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin. This is not consistent with the defined obligations of DR compared to other capacity resources. DR capacity resources do not have a must offer obligation in the energy market. DR capacity resources do not have a must offer obligation in the capacity market. The definition of performance for DR is not to provide a defined incremental level of MW when called but is only to be at a defined level of demand. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in the 2025/2026 and 2026/2027 Delivery Years will rely on demand response resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets for the first time in the 2025/2026 and 2026/2027 Delivery Years will experience the implications of the definition of demand resources as a purely emergency capacity resource, when demand resources are a significant share of required reserves. Nonetheless, as another significant flaw in the market design, PJM does not include DR in its definition of primary or secondary reserves in the energy market. DR, for all these reasons, is an inferior resource in the capacity market. PJM does not have clear rules defining when the operators must call on DR.

There are currently two important gaps in the market power rules for the PJM Capacity Market related to demand resources. The RPM must offer requirement is not applied to demand resources. There are no market power mitigation rules that apply to demand resources.

For the 2026/2027 BRA, all participants to which the three pivotal supplier (TPS) test was applied (in the RTO RPM market) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[115] [116]

The correct definition of a competitive offer in the capacity market is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with mitigating rational capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the PAI penalty rate is unsupported by economic logic. The use

115 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

116 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and increases CPQR above rational levels, and ultimately raises the price of capacity above the competitive level. Given PJM's recent decision to rely on conservative operations during tight market conditions as evidenced during Polar Vortex 2025 in January 2025, the probability of a PAI is extremely small. In addition, PJM tightened the definition of a PAI and capped the total annual penalty at 1.5 times the resource's capacity market BRA clearing price. As a result, there is no effective performance incentive remaining in the capacity market.

Rather than penalizing capacity resources at extremely high levels for nonperformance only during PAI events, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI events. CP has not worked as the theory suggested. PAI events are high impact, low probability events. The failure of the PAI incentives to prevent a very high level of outages during Winter Storm Elliott illustrates the weakness of incentives based on this type of event. In addition, the actual performance standards were unacceptably weakened in the CP model. The standard of performance in the CP model is (B) * (ELCC accredited UCAP factor for a unit), where B is the balancing ratio and the ELCC accredited UCAP factor is the derating factor. For example, if B were 80 percent, the actual required performance for a unit with an 80 percent ELCC accredited UCAP factor would be only 64 percent of ICAP (.80 * .80). For units with low ELCC accredited UCAP factors, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[117] [118] [119] [120] [121] [122] [123] [124] [125] [126] [127] [128] [129] In the first nine months of 2025, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. A majority of capacity investments in PJM were financed by market sources. Of the 57,618.3 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2024/2025 Delivery Years, 43,653.8 MW (76.0 percent) were based on market funding. Of the 5,661.6 MW of additional capacity that cleared in RPM auctions for the 2025/2026 and 2026/2027 Delivery Years, 4,487.6 MW (79.3 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

117 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," (July 6, 2016) <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf>.
118 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," (August 31, 2016) <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf>.
119 See "Analysis of the 2020/2021 RPM Base Residual Auction," (November 11, 2017) <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf>.
120 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," (August 24, 2018) <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf>.
121 See "Analysis of the 2022/2023 RPM Base Residual Auction," (February 22, 2022) <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.
122 See "Analysis of the 2023/2024 RPM Base Residual Auction," (October 28, 2022) <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>.
123 See the "Analysis of the 2024/2025 RPM Base Residual Auction," (October 30, 2023) <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf>.
124 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," (December 14, 2017) <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf>.
125 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," (September 13, 2019) <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf>.
126 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>.
127 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf>.
128 See Monitoring Analytics, L.L.C., Analysis of the 2025/2026 Base Residual Auction, Parts A through H, <https://www.monitoringanalytics.com/reports/Reports/2024.shtml> and https://www.monitoringanalytics. com/reports/Reports/2025.shtml>.
129 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Overview: Section 6, Demand Response

- **Demand Response Activity.** Demand response resources include economic demand response (energy market demand resources), emergency demand response, pre-emergency demand response and price responsive demand (PRD) (capacity market demand resources), synchronized reserves and regulation.[130]

  Total demand response revenue increased by $221.8 million, 194.2 percent, from $114.2 million in the first nine months of 2024 to $336.0 million in the first nine months of 2025, primarily due to increases in capacity market revenue. Emergency demand response revenue accounted for 85.9 percent of all demand response revenue, economic demand response for 6.1 percent, demand response in the synchronized reserve market for 4.2 percent and demand response in the regulation market for 3.8 percent.

  Total emergency demand response revenue increased by $201.5 million, 231.5 percent, from $87.0 million in the first nine months of 2024 to $288.5 million in the first nine months of 2025.[131] This increase was primarily a result of higher capacity market prices and capacity market revenue.

  Economic demand response revenue increased by $11.8 million, 134.4 percent, from $8.7 million in the first nine months of 2024 to $20.5 million in the first nine months of 2025.[132] Demand response revenue in the synchronized reserve market increased by $5.9 million, 70.7 percent, from $8.3 million in the first nine months of 2024 to $14.2 million in the first nine months of 2025. Demand response revenue in the regulation market increased by $2.7 million, 26.5 percent, from $10.1 million in the first nine months of 2024 to $12.8 million in the first nine months of 2025.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments to demand response resources although emergency demand response and economic demand response can and do set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time energy market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[133]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in the first nine months of 2024 and 2025. The HHI for economic demand response resource reductions decreased by 46 points from 8846 in the first nine months of 2024 to 8800 in the first nine months of 2025.

  The ownership of emergency demand response resources is highly concentrated. The HHI for emergency demand response resources committed MW was 2387 for the 2024/2025 Delivery Year. In the 2024/2025 Delivery Year, the four largest CSPs owned 88.5 percent of all committed emergency demand response UCAP MW. The HHI for

130 Emergency demand response refers to both emergency and pre-emergency demand response.
131 The total credits and MWh numbers for demand resources were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates.
132 Economic credits are synonymous with revenue received for reductions under the economic load response program.
133 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 102 (Oct. 1, 2025).

emergency demand response committed MW is 2517 for the 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, the four largest CSPs own 86.7 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. In addition, aggregation rules allow a demand resource that incorporates many small End Use Customers to span an entire zone, which is inconsistent with nodal dispatch.
- **Energy Efficiency.** Energy efficiency payments have been eliminated from PJM markets effective June 1, 2026. Energy efficiency resources are not capacity resources in PJM and do not clear in the capacity market. The total MW of energy efficiency resources paid decreased by 80.6 percent, from 7,716.0 MW in the 2024/2025 Delivery Year to 1,493.2 MW in the 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, payments to EE are $148 million.
- **Energy Efficiency Payments are a Subsidy and Uplift.** Payments from the buyers of capacity to energy efficiency providers are a subsidy and uplift. Energy efficiency is not a capacity resource and does not contribute to reliability.
- **Energy Efficiency Market Concentration.** The HHI for energy efficiency on an aggregate market basis shows that ownership is highly concentrated. The four largest companies own 90 percent or more of all paid Energy Efficiency MW. The HHI for Energy Efficiency resources also shows that ownership is highly concentrated for the 2025/2026 Delivery Year, with an HHI value of 2804. In the 2025/2026 Delivery Year, the four largest companies own 96.0 percent of all paid Energy Efficiency MW.

Section 6 Recommendations

- The MMU recommends that PJM report the response of emergency demand response resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the expected response to PJM dispatch. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that emergency demand response resources offering as supply in the capacity market be required to offer a guaranteed load drop (GLD) below their PLC to ensure that demand resources provide an identifiable MW resource to PJM when called. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends, as an alternative to including emergency demand response resources as supply in the capacity market, that demand resources have the option to be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for emergency demand response resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[134] (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for emergency demand response resources and price response demand resources be the same as the maximum offer for generation resources and that the same cost verification rules applied to generation resources apply to demand resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the emergency demand response resources be treated as economic resources, responding to economic price signals like

134 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

other capacity resources. The MMU recommends that emergency demand response resources not be treated as emergency resources. The MMU recommends that emergency demand response resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Partially adopted.)

- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market prices is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if emergency demand response resources remain in the capacity market, a daily energy market must offer requirement apply to emergency demand response resources, comparable to the rule applicable to generation capacity resources.[135] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that emergency demand response resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of emergency demand response resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for all demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[136] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all emergency demand response resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that demand response testing be initiated by PJM with advance notice to CSPs identical to the actual lead time required in an emergency in order to accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that economic demand response resources be paid LMP less any generation

135 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

136 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)

- The MMU recommends that the tariff rules for emergency demand response resources clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[137])
- The MMU recommends that all demand resources register as Pre-Emergency and that the Emergency Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that the lead times for emergency demand response resources be shortened to 30 minutes with a one hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)

137 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

- The MMU recommends that energy efficiency resources (EE) not be included in the capacity market mechanism and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately. (Priority: Medium. First reported 2018. Status: Adopted 2024.)[138] [139]
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation. (Priority: Medium. First reported 2022. Status: Partially adopted.)
- The MMU recommends that the Commission require PJM to include in OATT Attachment M the explicit statement that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DERs. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that net metering resources be prohibited from participating in wholesale ancillary services markets if they are

138 See 189 FERC ¶ 61,095.
139 Originally incorporated with auctions conducted in 2016 for the 2016/2017 Delivery Year and forward. The mechanics of the EE addback mechanism were modified beginning with the 2023/2024 Delivery Year.

compensated for the service at the retail level. (Priority: Medium. First reported Q2, 2025. Status: Not adopted.)

- The MMU recommends that PJM revise the requirements for reporting expected real time energy load reductions by CSPs to PJM to improve the accuracy and usefulness to PJM's system operators. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI. The MMU recommends that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: Medium. New recommendation. Status: Not adopted.)

Section 6 Conclusion

A fully functional demand side of the electricity market means that End Use Customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on how customers value the power and on the actual cost of that power.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. Demand resources do not have telemetry requirements similar to other Capacity Performance resources. Until July 30, 2023, including Winter Storm Elliott, PJM automatically, and inappropriately, triggered a PAI when demand resources were dispatched.

In order to be a substitute for generation, demand resources offering as supply in the capacity market should be required to offer a guaranteed load drop (GLD) below their PLC to ensure that demand resources provide an identifiable MW resource to PJM when called.

In order to be a substitute for generation, the ELCC for demand resources should be based on data about actual reductions in demand during high expected loss of load hours, like other capacity resources. The current DR ELCC is significantly overstated because the DR ELCC value is based on the unsupported assumption that the full amount of capacity sold will respond when called rather than on actual response data. In other words, the actual response is assumed to be perfect. The amount of capacity sold equals the PLC – the FSL for the resource. PJM has proposed to make this problem worse rather than to correct it, by increasing the ELCC of demand resources based on assumptions rather than actual performance data.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that demand resources are only obligated to respond for defined time periods meant that PJM could not fully use demand resources during Winter Storm Elliott (Elliott). Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called whenever economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. Compliance of demand resources for capacity purposes during a Performance Assessment Event is measured relative to either Peak Load Contribution or Winter Peak Load, which are static values. If a demand resource's metered load increases above these reference values during a PAI, the current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.[140]

140 See PJM. MC Webinar, Market Monitor Report <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230620-webinar/item-04---imm-report.ashx> (June 20, 2023).

In order to be a substitute for generation, Actual Performance of demand resources during a Performance Assessment Event should be determined consistent with that of generation and should not be netted across the Emergency Action Area (EAA). The Capacity Market Seller's Performance Shortfalls for Demand Resources in the EAA are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller's demand resources that under complied within the EAA on a prorata basis based on the under compliance MW, and such seller's demand resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller's Demand Resources that over complied within the EAA on a prorata basis based on over compliance MW, and such Market Seller's Demand Resources will be assessed Bonus Performance. Netting of performance of Demand Resources across the EAA is inconsistent with the performance measurement of other Capacity Performance resources.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As an alternative to being a substitute for generation in the capacity market, demand response resources should have the option to be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol, and PJM forecasts would immediately incorporate the impacts of demand side behavior.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[141] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[142] [143] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance is measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[144] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours, not limited to a small number of peak hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE. But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market. That transition should be defined by the rules proposed by the MMU.

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in EPSA as it does not depend on whether FERC has jurisdiction over the demand side.[145] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

141 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.

142 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (March 9, 2018).

143 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (April 13, 2018).

144 The PJM proposal from the SODRSTF weakened the proposal but was approved at the October 25, 2018 Members Committee meeting and PJM filed Tariff changes on December 7, 2018. See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

145 577 U.S. 260 (2016).

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP). If a demand resource location was already at a reduced load level when PJM called a PAI, the demand resource would be deemed to have performed if the PLC less the metered load level was equal to the ICAP sold in the capacity market. The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response. That is exactly what happened during Elliott. In addition, PRD is not required to respond if the LMP is less than the PRD strike price. This flawed rule meant that PRD did not fully respond during Winter Storm Elliott because PRD offered at the maximum price of $1,849 per MWh.

Overview: Section 7, Net Revenue

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices, gas prices and coal prices increased in the first nine months of 2025 compared to the first nine months of 2024. The net effects were that in the first nine months of 2025, average energy market theoretical net revenues increased by 30 percent for a new combustion turbine (CT), increased by 35 percent for a new combined cycle (CC), increased by 148 percent for a new coal plant (CP), increased by 46 percent for a new nuclear plant, increased by 279 percent for a new diesel (DS), increased by 52 percent for a new onshore wind installation, increased by 49 percent for a new offshore wind installation and increased by 42 percent for a new solar installation.
- The price of natural gas and coal increased in the first nine months of 2025. The marginal costs of a new CT were greater than the marginal cost of a new CP only in January, February and March 2025. The marginal costs of a new CC were greater than the marginal cost of a new CP only in January 2025.
- In the first nine months of 2025, spark spreads and dark spreads and the volatility of spark spreads and dark spreads increased in BGE, COMED and Western Hub compared to the first nine months of 2024. In the first nine months of 2025, spark spreads decreased while dark spreads and the volatility of both spark spreads and dark spreads increased in PSEG compared to the first nine months of 2024.
- Of the 16 PJM nuclear plants analyzed, all are expected to cover their avoidable costs from energy and capacity market revenues in 2025, 2026 and 2027, without any subsidies.

Section 7 Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical revenues that are scaled based on forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 7 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals alone has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs. A basic purpose of the capacity market is to allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market.

PJM's introduction of a form of ELCC for defining available capacity has made the definition of reliability less clear. The ELCC derate factors are volatile and subject to changes for reasons that are not clear to generation owners or other market participants. There are significant issues with PJM's implementation of its approach to ELCC.

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[146] On April 24, 2024, the EPA finalized a strengthened and updated MATS rule reflecting recent developments in control technologies and the performance of coal fired plants.[147] On June 11, 2025, the EPA proposed to repeal the core changes of the 2024 amendments,[148] including the revised filterable particulate matter (fPM) emission standard, restoring the 0.030 lbs/MMBtu standard.[149]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[150] (Transport Rule) On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[151] On February 28, 2022, the EPA issued a federal implementation plan for implementation of CSAPR (also known as the Good Neighbor Plan),[152] which applies when no state implementation plan has been approved. On June 27, 2024, the Supreme Court of the United States granted a stay of the federal implementation plan pending judicial review.[153] The effect of the stay is to eliminate the ozone season NO_X emissions budgets for electric generating units in the PJM states. Unless and until the stay is lifted, no federal implementation plan is effective in PJM states and the state emissions budgets are not effective. The EPA had previously rejected all proposed state implementation plans for PJM states. Under the new administration the future of the federal implementation plan is uncertain, and attempts to create state implementation plans are expected to resume.

- **NSR.** The CAA's NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.[154] NSR requires permits before construction commences. NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units.[155]

146 See *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).
147 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, Final Rule, Docket No. EPA-HQ-OAR-2018-0794, 89 Fed. Reg. 38508 (May 7, 2024).
148 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, Final Rule, Docket No. EPA-HQ-OAR-2018-0794, 89 Fed. Reg. 38508 (May 7, 2024).
149 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA–HQ–OAR–2018–0794; FRL–6716.4–01–OAR, 90 Fed. Reg. 25535 (June 17, 2025).
150 CAA § 110(a)(2)(D)(i)(I).
151 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA–HQ–OAR–2020–0272; FRL–10013–42– OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
152 See *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Docket No. EPA–HQ–OAR–2021–0668; FRL 8670–01–OAR, 87 Fed. Reg. 20036 (April 6, 2022).
153 Ohio v. EPA, Slip Op. No. 23A349. (S. Ct. June 27, 2024); Utah v. EPA, D.C. Cir. Case No. Case No. 23-1157, et al.
154 42 U.S.C § 7470 et seq.
155 40 CFR § 52.21.

- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[156] Environmental regulations allow stationary emergency RICE that do not meet the emissions limits and are participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

  PJM does not prevent stationary emergency RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some stationary emergency RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Stationary emergency RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

- **Greenhouse Gas Emissions.** On April 25, 2024, the EPA issued a rule (called "Carbon Emissions Rule" in this report) taking four separate actions under CAA § 111(a)(1) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs):[157] the rule repeals the Affordable Clean Energy (ACE) Rule; the rule finalizes emission guidelines for GHG emissions from existing coal fired and oil/gas fired steam generating EGUs; the rule revises the New Source Performance Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs; the rule revises the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The rule deferred action on emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines.

  The Carbon Emissions Rule reflects the application of the best system of emission reduction (BSER). The proposal includes emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs (including coal, oil or gas). For coal fired EGUs, compliance is required by January 1, 2030, with standards that vary based on whether the EGU commits to retire before 2032, 2035, 2040, or does not commit to retire before 2040.[158] The Carbon Emissions Rule proposes to repeal the Affordable Clean Energy Rule.[159]

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[160]

- **Waters of the United States.** On August 29, 2023, the EPA issued a final rule defining adjacent wetlands consistent with the Supreme Court holding that an adjacent wetland is "... a relatively permanent body of water connected to traditional interstate navigable waters ... and ... that the wetland has a continuous surface connection with that water."[161] The rule became effective on September 8, 2023.[162]

- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. Since 2015, the EPA has been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result. In May 2024, the EPA finalized a rule strengthening regulation of effluent discharges.[163]

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[164]

156 See 40 CFR § 63.6640(f).
157 See *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, Proposed Rule, Docket No. EPA-HQ-OAR-2023-0072, 89 Fed. Reg. 39798 (May 9, 2024) ("Carbon Emissions Rule").
158 Carbon Emissions Rule at 33371-33373.
159 Carbon Emissions Rule at 33243.
160 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (August 15, 2014).
161 See Revised Definition of "Waters of the United States," EPA-HQ-OW-2023-0346, 88 Fed. Reg. 61964 (September 8, 2023).
162 See *id.*
163 See *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Final Rule, EPA Docket No. EPA-HQ-OW-2009-0819; FRL-8794-01- OW, 89 Fed. Reg. 40199 (May 9, 2024).
164 42 U.S.C. §§ 6901 *et seq.*

The EPA has adopted significant changes to the implementing regulations that will require closing noncompliant impoundments, and, as a result, the host power plant. The EPA is implementing a process for extensions to as late as October 17, 2028. The EPA is reviewing applications received from PJM plant owners for extensions of the deadline for compliance with the revised Coal Combustion Residuals Rule.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont that applies to power generation facilities. The most recent RGGI auction, held on September 3, 2025, cleared at $22.25 per short ton, or $24.53 per metric tonne.
- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandated that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis. More than 10,000 MW of capacity are currently affected. The CEJA operating hour limits have resulted in significant opportunity cost adders to cost-based energy market offers for affected units.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would have increased by $24.45 per MWh or 62.1 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 57.7 percent for a new combined cycle (CC) unit and $43.12 per MWh or 111.4 percent for a new coal plant (CP) for the first nine months of 2025.
- **Offshore Wind.** New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[165] On January 20, 2025, the Trump Administration issued a Presidential Memorandum withdrawing "from disposition for wind energy leasing all areas within the Offshore Continental Shelf."[166] The withdrawal effectively puts on hold indefinitely the offshore wind projects in New Jersey and Maryland. On May 5, 2025, the Attorneys General of New Jersey and Maryland, along with the 16 other states, filed suit against the withdrawal of offshore leasing.[167]

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of September 30, 2025, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Indiana has a voluntary renewable portfolio standard. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $14.6 billion over the ten year period from 2014 through 2023, an average annual RPS compliance cost of $1.5 billion. The compliance cost for 2023, the most recent year with almost complete data, was $2.9 billion.[168]

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.

165 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.

166 *Temporary Withdrawal of all Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects*, Presidential Memorandum (January 20, 2025) <https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/>.

167 *State of New York v. Trump*, Case No. 1:25-cv-11221 (Dist. of Mass. May 5, 2025).

168 The 2023 compliance cost value for PJM states does not include Delaware, Michigan or North Carolina. Based on past data these states generally account for approximately 2.0 percent of the total RPS compliance cost of PJM states.

- **Emissions Controls.** In PJM, as of September 30, 2025, 98.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, 99.8 percent of coal steam MW had some type of particulate matter (PM) control, and 99.7 percent of coal steam MW had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 6.5 percent of total generation in PJM for the first nine months of 2025. RPS Tier I generation was 7.6 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM for the first nine months of 2025. Only Tier I generation is defined to be renewable but Tier I includes some carbon emitting generation.

  PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first nine months of 2025, Tier I generation from PJM generators met only 46.8 percent of the Tier I RPS requirements.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that stationary emergency RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets.

Environmental requirements and initiatives at both the federal and state levels, and state renewable energy mandates and associated subsidies have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources, and the retirement of emitting resources. Renewable energy credit (REC) markets created by state programs, federal subsidies, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, including supporting some emitting resources, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

In the absence of a PJM market carbon price, a single PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor.

RECs are an important mechanism used by PJM states to implement environmental policy. RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data.

Existing REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The economic logic of RPS programs and the associated REC and SREC prices are not always clear. The price of carbon implied by REC prices ranges from $10.24 per tonne in Ohio to $65.23 per tonne in Virginia. The price of carbon implied by SREC prices ranges from $69.05 per tonne in Pennsylvania to $832.21 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in September 2025 of $24.53 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[169] [170] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.85 per MWh.[171] The impact of an $800 per tonne carbon price would be $269.59 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad

169 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

170 A recent update by the EPA estimates the social cost of carbon emissions for 2030 to be between $140 and $380 per metric ton (2020 dollars). See Table ES.1 in Report on the Social Cost of Greenhouse Gases, U.S. Environmental Protection Agency (November 2023) <https://www.epa.gov/environmental-economics/scghg>.

171 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 52.91 kg per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2025 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-9.

market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

If the states chose this policy option, PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. The results of the analysis would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state.

For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the ten year period from 2014 through 2023 for the ten jurisdictions that had RPS was $1.5 billion, or a total of $14.6 billion over ten years. The RPS compliance cost for 2023, the most recent year for which there is almost complete data, was $2.9 billion.[172] RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $7.4 billion per year if the carbon price were $22.25 per short ton and emissions levels were five percent below 2024 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $16.5 billion if the carbon price were $50 per short ton and emission levels were five percent below 2024 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $22.25 per short ton would be about $5.0 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2025, PJM was a monthly net exporter of energy in the real-time energy market in all months.[173] In the first nine months of 2025, the real-time net interchange was -29,800.7 GWh. The real-time net interchange in the first nine months of 2024 was -27,542.0 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first nine months of 2025,

172 The 2023 compliance cost value for PJM states does not include Delaware, Michigan or North Carolina. Based on past data these states generally account for approximately 2.0 percent of the total RPS compliance cost of PJM states.
173 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

the total day-ahead net interchange was -26,230.6 GWh. The day-ahead net interchange in the first nine months of 2024 was -24,393.4 GWh.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2025, gross imports in the day-ahead energy market were 62.0 percent of gross imports in the real-time energy market (75.3 percent in the first nine months of 2024). In the first nine months of 2025, gross exports in the day-ahead energy market were 80.4 percent of the gross exports in the real-time energy market (84.8 percent in the first nine months of 2024).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2025, there were net scheduled exports at 14 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2025, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions in the real-time energy market.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, there were net scheduled exports at 15 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market. In the first nine months of 2025, up to congestion transactions were net exports at three of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Inadvertent Interchange.** In the first nine months of 2025, net scheduled interchange was -29,800.7 GWh and net actual interchange was -29,592.4 GWh, a difference of 208.4 GWh. In the first nine months of 2024, the difference was 196.4 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first nine months of 2025, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -799.7 GWh of net scheduled interchange and -8,409.3 GWh of net actual interchange, a difference of 7,609.6 GWh. In the first nine months of 2025, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 2,746.0 GWh of net scheduled interchange and 6,535.3 GWh of net actual interchange, a difference of 3,789.3 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2025, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 52.4 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2025, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 59.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 81.5 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 80.3 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 80.7 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in the first nine months of 2025, and zero such TLRs in the first nine months of 2024.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 57.7 percent, from 36,083 bids per day in the first nine months of 2024 to 48,979 bids per day in the first nine months of 2025. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 10.1 percent, from 237,417 MWh per day in the first nine months of 2024, to 264,091 MWh per day in the first nine months of 2025.

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to

three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)

- The MMU recommends eliminating the mechanism that defines FFE and M2M payments. These mechanisms are not consistent with markets and are not needed for efficient interface pricing. The MMU recommends that PJM file with the Commission to eliminate the FFE calculation and M2M payment of the PJM and MISO joint operating agreement. (Priority: Medium. First reported 2024. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends clear rules governing when PJM may recall capacity backed exports. (Priority: Medium. First reported 2010. Status: Partially adopted.)

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features of an energy market including locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features. Pricing in the market areas is transparent and pricing in the nonmarket areas is not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market across the interfaces.

It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. External entities wishing to receive the benefits of the PJM LMP market should join PJM.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. Following the termination of the Northwest pricing point on October 1, 2020, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The MMU continues to recommend the termination of the Ontario interface pricing point. The Ontario interface pricing point is noncontiguous to the PJM footprint that creates opportunities for market participants to engage in sham scheduling activities.

Overview: Section 10, Ancillary Services

Primary Reserve

Primary reserves consist of both synchronized and nonsynchronized reserves that can provide energy within 10 minutes and sustain that output for at least 30 minutes during a contingency event. PJM made several changes to the primary reserve market, effective October 1, 2022. These included a must offer requirement and correction of misspecified cost-based offers. By removing opportunities for physical and economic withholding, the changes resulted in clearing increased quantities of available synchronized reserves at competitive prices. Starting in May 2023, to compensate for poor unit specific resource performance, PJM unilaterally increased the synchronized reserve reliability requirement, which in turn increased the primary reserve reliability requirement.

Market Structure

- **Supply.** Primary reserve is provided by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes) and nonsynchronized reserve (generation currently offline but available to start and provide energy within 10 minutes).
- **Demand.** The primary reserve reliability requirement is equal to 150 percent of the synchronized reserve reliability requirement. The primary reserve requirement is equal to the primary reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement (190 MW), with a shortage penalty price of $300 per MWh. The synchronized reserve requirement is equal to the synchronized reserve reliability requirement plus the extended reserve requirement, with a default level of 190 MW. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Starting in May 2023, PJM increased the size of the synchronized reserve reliability requirement in the RTO Reserve Zone by 30 percentage points to 130 percent of the most severe single contingency (MSSC), in effect increasing the primary reserve reliability requirement to 195 percent of the MSSC. In the first nine months of 2025, the real-time average primary reserve requirement was 3,401.4 MW in the RTO Reserve Zone and 2,584.7 MW in the Mid-Atlantic Dominion Reserve Subzone. In the first nine months of 2025, the day-ahead average primary reserve requirement was 3,384.4 MW in the RTO Reserve Zone and 2,559.0 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** Both the Mid-Atlantic Dominion (MAD) Reserve Subzone Market and the RTO Reserve Zone Market for primary reserve were characterized by structural market power in the first nine months of 2025. The average HHI for real-time primary reserve in the RTO Reserve Zone was 980, which is classified as unconcentrated. The average HHI for day-ahead primary reserve in the RTO Zone was 915, which is classified as unconcentrated. The average HHI for real-time primary reserve in the MAD Reserve Subzone was 1563, which is classified as moderately concentrated. The average HHI for day-ahead primary reserve in the MAD Reserve Subzone was 1401, which is classified as moderately concentrated.

Synchronized Reserve Market

Synchronized reserves include all capacity synchronized to the grid and available to satisfy PJM's power balance requirements within 10 minutes. This includes online resources loaded below their full output, storage or condensing resources synchronized to the grid but consuming energy, and 10-minute demand response capability. As of October 1, 2022, all generation capacity resources must offer their entire synchronized reserve capability to the PJM market at all times. PJM jointly optimizes energy, synchronized reserve, primary reserve, and 30-minute reserve needs in both the day-ahead and real-time markets. Synchronized reserve prices are based on opportunity costs calculated by PJM in the market optimization and the anticipated cost of a performance penalty. All real-time cleared synchronized reserves are obligated to perform when PJM initiates a synchronized reserve event based on a loss of supply.

Market Structure

- **Supply.** In the first nine months of 2025, the real-time average supply of available synchronized reserve was 5,763.4 MW in the RTO Reserve Zone, of which 2,814.0 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone. In the first nine months of 2025, the day-ahead average supply of available synchronized reserve was 6,664.6 MW in the RTO Reserve Zone, of which 3,392.5 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** The synchronized reserve requirement is equal to the synchronized reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement, with a shortage penalty price of $300 per MWh and a default value of 190 MW. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Since May 19, 2023, PJM has inappropriately set the synchronized reserve reliability requirement to 130 percent of the MSSC for the RTO Reserve Zone. The real-time average synchronized reserve requirement in the first nine months of 2025 was 2,330.9 MW in the RTO Reserve Zone and 1,786.4 MW in the Mid-Atlantic Dominion Reserve Subzone. The day-ahead average synchronized reserve requirement in the first nine months of 2025 was 2,319.6 MW in the RTO Reserve Zone and 1,769.4 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion (MAD) Reserve Subzone Market for synchronized reserve was characterized by structural market power in the first nine months of 2025. The average HHI for real-time synchronized reserve in the RTO Reserve Zone was 911, which is classified as unconcentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 799, which is classified as unconcentrated. The average HHI for real-time synchronized reserve in the MAD Reserve Subzone was 1721, which is classified as moderately concentrated. The average HHI for day-ahead synchronized reserve in the MAD Reserve Subzone was 1341, which is classified as moderately concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for synchronized reserve. All nonemergency generation capacity resources are required to offer their entire synchronized reserve capability. PJM calculates the available synchronized reserve for all conventional resources based on the energy offer ramp rate, energy dispatch point, and the lesser of the synchronized reserve maximum or economic maximum output. Hydro resources, energy storage resources, and demand response resources submit their available synchronized reserve MW. Wind, solar, and nuclear resources are by default considered incapable of providing synchronized reserve, but may offer with an exception approved by PJM. Synchronized reserve offers are capped at cost plus the expected value of performance penalties. PJM calculates opportunity costs based on LMP.

  Significant communications technology and modelling issues when calling resources during spinning events continue to result in slow response from a significant share of resources.

Market Performance

- **Price.** In the first nine months of 2025, for the Mid-Atlantic Dominion Reserve Subzone, the weighted average real-time price for synchronized reserve was $3.94 per MWh and the weighted average day-ahead price was $6.26 per MWh. In the first nine months of 2025, for the RTO Reserve Zone, the weighted average real-time price for synchronized reserve was $4.55 per MWh and the weighted average day-ahead price was $6.23 per MWh.

Nonsynchronized Reserve

Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to meet the portions of the primary reserve requirement and the 30-minute reserve requirement not already satisfied by reserve cleared for the synchronized reserve requirement.

Market Structure

- **Supply.** In the first nine months of 2025, the real-time average supply of eligible and available nonsynchronized reserve was 1,006.5 MW in the RTO Reserve Zone, of which 614.1 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone. In the first nine months of 2025, the real-time average supply of eligible and available nonsynchronized reserve was 1,039.6 MW in the RTO Reserve Zone, of which 476.9 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** Demand for nonsynchronized reserve is the primary reserve requirement less the amount of synchronized reserves cleared by PJM.[174] Although nonsynchronized reserve can be used to meet the 30-minute reserve requirement, any 30-minute reserve beyond the primary reserve requirement is usually provided by secondary reserve due to its lower cost and greater availability.

Market Conduct

- **Offers.** Generation owners do not submit supply offers for nonsynchronized reserve from non-hydroelectric units. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are defined to be available for nonsynchronized reserves. For non-hydroelectric units, PJM calculates the MW available from a unit based on the unit's energy offer. Hydroelectric units set their own offered reserve amount. For all units, the offer price of nonsynchronized reserve is $0 per MWh.[175] Hybrid units and energy storage resources are not eligible to provide nonsynchronized reserves.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the marginal primary reserve resource. In the first nine months of 2025, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $1.87 per MWh and the weighted average day-ahead price was $2.42 per MWh. In the first nine months of 2025, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $2.22 per MWh and the weighted average day-ahead price was $3.43 per MWh.

30-Minute Reserve Market

The supply of 30-minute reserves consists of resources, online or offline, which can respond within 30 minutes. This includes primary reserves and secondary reserves. There is no reserve subzone for 30-minute reserves.

Market Structure

- **Supply.** The supply of 30-minute reserve is provided by both primary reserve (synchronized and nonsynchronized resources that can provide energy within 10 minutes) and secondary reserve (synchronized and nonsynchronized resources that can provide energy within 30 minutes but that take more than 10 minutes). In the first nine months of 2025, the real-time average supply of available 30-minute reserve was 27,655.6 MW in the RTO Zone.
- **Demand.** The 30-minute reserve requirement is equal to the 30-minute reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement (190 MW), with a shortage penalty price of $300 per MWh. The 30-minute reserve reliability requirement is equal to the maximum of: the primary reserve reliability requirement; the largest active gas contingency; and 3,000 MW. Since PJM increased the synchronized reserve reliability requirement, the 30-minute reserve reliability requirement is frequently equal to the primary reserve reliability requirement. In the first nine months of 2025, the average 30-minute reserve requirement was 3,519.5 MW in the real-time market and 3,508.8 MW in the day-ahead market.
- **Market Concentration.** The RTO Reserve Zone Market for 30-minute reserves was characterized by moderate structural market power in the first nine months of 2025. In the first nine months of 2025, the average HHI for real-time 30-minute reserves was 869, which is classified as unconcentrated. In the first nine months of 2025, the average HHI for day-ahead 30-minute reserves was 857, which is classified as unconcentrated.

174 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 134 (Apr. 23, 2025).
175 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 134 (Apr. 23, 2025).

Secondary Reserve

Secondary reserves are reserves that take more than 10 minutes to convert to energy, but less than 30 minutes. This includes the unloaded capacity of online generation that can be achieved according to the resource ramp rates in 10 to 30 minutes, and offline resources with a start time of less than 30 minutes. Secondary reserves can only be used to satisfy the 30-minute reserve requirement.

Market Structure

- **Supply.** In the first nine months of 2025, in the RTO Reserve Zone, the real-time average supply of available secondary reserve was 21,163.8 MW and the day-ahead average supply of available secondary reserve was 12,402.1 MW. As with the 30-minute reserve service, there is no defined reserve subzone for secondary reserves.
- **Demand.** Demand for secondary reserve is the 30-minute reserve requirement less the amount of primary reserves cleared by PJM.[176]

Market Conduct

- **Offers.** Energy storage resources, hydroelectric resources, hybrid resources, and demand-side response resources submit their available secondary reserve MW. For all other resource types, PJM calculates the MW available from a resource based on the resource's energy offer. For all resources, the offer price of secondary reserve is $0 per MWh.[177] In both the day-ahead and real-time secondary reserves markets, PJM uses lost opportunity costs as the offers and not offers submitted by market participants. For online secondary reserves, PJM calculates an opportunity cost based on LMP.

Market Performance

- **Price.** The secondary reserve price is determined by the marginal 30-minute reserve resource. In the first nine months of 2025, the secondary reserve real-time price for all intervals was $0.01 per MWh. In the first nine months of 2025, the secondary reserve day-ahead price for all intervals was $0.00 per MWh.

176 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 134 (Apr. 23, 2025).
177 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 134 (Apr. 23, 2025).

Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp rates. The RegD signal is designed for energy limited resources with fast ramp rates. In the regulation market RegD MW are converted to effective MW using a marginal rate of technical substitution (MRTS), called a marginal benefit factor (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the regulation market.

PJM filed significant changes to the regulation market design on April 16, 2024, that were accepted as filed by order of June 17, 2024.[178] PJM will implement the changes to the regulation market in two phases. Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The proposed Phase 1 changes will eliminate many of the significant issues identified by the MMU that have resulted from a two product, two signal market design including the incorrect and inconsistent use and application of the MBF/MRTS.

This report analyzes the current (as of the third quarter of 2025) regulation market design and results during the first nine months of 2025.

178 PJM, "Regulation Market Design Filing," Docket No. ER24-1772-000 (April 16, 2024).

Market Structure

- **Supply.** In the first nine months of 2025, the average hourly offered supply of regulation for nonramp hours was 788.7 performance adjusted MW (787.2 effective MW). This was an increase of 93.2 performance adjusted MW (an increase of 78.9 effective MW) from the first nine months of 2024, when the average hourly offered supply of regulation was 695.5 actual MW (708.3 effective MW). In the first nine months of 2025, the average hourly offered supply of regulation for ramp hours was 1,063.0 performance adjusted MW (1,119.1 effective MW). This was an increase of 68.6 performance adjusted MW (an increase of 72.1 effective MW) from the first nine months of 2024, when the average hourly offered supply of regulation was 994.4 performance adjusted MW (1,047.0 effective MW).
- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 486.9 hourly average performance adjusted actual MW in the first nine months of 2025. This is an increase of 8.3 performance adjusted actual MW from the first nine months of 2024, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 478.5 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 690.8 hourly average performance adjusted actual MW in the first nine months of 2025. This is a decrease of 6.6 performance adjusted actual MW from the first nine months of 2024, where the average hourly regulation cleared MW for ramp hours were 697.5 performance adjusted actual MW.

  The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.62 in the first nine months of 2025 (1.45 in the first nine months of 2024). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.54 in the first nine months of 2025 (1.42 in the first nine months of 2024).
- **Market Concentration.** In the first nine months of 2025, the three pivotal supplier test was failed in 94.2 percent of hours. In the first nine months of 2025, the effective MW weighted average HHI of RegA resources was 2632 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 2015 which is also highly concentrated. The effective MW weighted average HHI of all resources was 1315, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[179] In the first nine months of 2025, there were 193 resources following the RegA signal and 60 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $42.42 per MW of regulation in the first nine months of 2025, an increase of $11.12 per MW, or 35.5 percent, from the weighted average clearing price of $31.30 per MW in the first nine months of 2024. The weighted average cost of regulation in the first nine months of 2025 was $52.35 per MW of regulation, an increase of 33.2 percent, from the weighted average cost of $39.31 per MW in the first nine months of 2024.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW.

179 See the *2024 Annual State of the Market Report for PJM*, Appendix F "Ancillary Services Markets."

- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[180]

In the first nine months of 2025, total black start charges were $39.6 million, a decrease of $15.6 million (28.3 percent) from 2024. In the first nine months of 2025, total revenue requirement charges were $39.2 million, a decrease of $15.7 million (28.6 percent) from 2024. In the first nine months of 2025, total black start uplift charges were $0.4 million, a increase of $.01 million (30.4 percent) from 2024. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive payment. Black start uplift charges are paid to units scheduled in the day-ahead energy market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in the first nine months of 2025 ranged from $0 in the OVEC and REC Zones to $6.6 million in the AEP Zone.

CRF values are a key determinant of total payments to black start units. The CRF values in PJM tariff tables should have been changed for both black start and the capacity market when the tax laws changed effective January 1, 2018. As a result of the failure to reduce the CRF values, black start units have been and continue to be significantly overcompensated since the changes to the tax code. In March 2023, FERC issued an order establishing hearing and settlement judge procedures.[181] By order issued September 23, 2025, the Commission approved a settlement over the MMU's objection that continued to allow overcompensation.[182] On July 4, 2025, enactment of the One Big Beautiful Bill Act (OBBBA) changed the rules for bonus depreciation again, allowing 100 percent bonus depreciation for assets constructed between January 20, 2025 and December 31, 2028, and placed in service before January 1, 2031.[183] The CRF values for affected units should incorporate 100 percent bonus depreciation. It is essential that PJM not repeat its earlier mistake when it ignored the tax law changes in 2017.

180 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVAr and MW. Generation resources are required to meet defined reactive capability requirements as a condition to receive interconnection service in PJM.[184] RTOs and their customers are not required to separately compensate generation resources for such reactive capability.[185] In the first nine months of 2025, PJM customers paid $273.1 million for reactive capability based on archaic, nonmarket and unsupported assertions about cost allocation and a regulatory review process of filings by individual units that results in unsupported black box settlements. The current rules have permitted over recovery of reactive costs through reactive capability charges. All costs of generators should be incorporated in the market.

181 See 182 FERC ¶ 61,194.
182 See 193 FERC ¶ 61,059.
183 OBBA § 70301(b)(3).
184 OATT Attachment O.
185 See 182 FERC ¶ 61,033 at P 52 (2023); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *California ISO*, 160 FERC ¶ 61,035 at P 19 (2017); 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022).

The nonmarket approach to reactive capability payments will be eliminated effective June 1, 2026, based on FERC's Order No. 904 and the order approving PJM's compliance filing.[186]

Reactive service charges based on opportunity costs are appropriately paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing real-time reactive power.

In the first nine months of 2025, total reactive charges were $273.7 million, a decrease of $12.1 million (4.24 percent) from 2024. In the first nine months of 2025, total reactive capability charges were $273.1 million, a decrease of $11.7 million (4.1 percent) from 2024. In the first nine months of 2025, total reactive service charges were $0.59 million, a decrease of $0.41 million (41.4 percent) from 2024.

Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $28.6 million in the AEP Zone in the first nine months of 2025.

Primary Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require all newly interconnecting non-nuclear generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[187]

Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 Hz deadband.[188] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events occurs two to three times per month. A frequency event is declared whenever the system frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz. Exclusions to PJM monitoring include nuclear plants, offline units, units with no available headroom, units assigned to regulation, and units with a current outage ticket in eDART. Effective June 2024 through June 2025, the NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to +/- 258.3 MW/0.1 Hz.[189]

The MMU has identified several issues with PJM's enforcement and evaluation of generation PFR performance.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services including synchronized reserves, primary reserves and 30-minute reserves, and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be included in the offer for the ancillary service. The degree to which PJM markets account for these interactions depends on the timing of the product clearing, software limitations, and the accuracy of resource parameters and offers.

All reserve products are jointly cleared with energy in every real-time market solution. The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services because dispatched energy and synchronized reserve are outputs of the same optimization problem for each market interval. Given the joint clearing of energy and flexible synchronized reserves, the synchronized reserve market clearing price should

186 See *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024); PJM compliance filing, Docket No. ER24-1073 (January 28, 2025); 192 FERC ¶ 61,113 (2025).
187 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.
188 OATT Attachment O § 4.7.2 (Primary Frequency Response).
189 See NERC. "2024 Frequency Bias Settings," June 11, 2024. <https://www.nerc.com/comm/OC/Documents/OY_2024_Frequency_Bias_Annual_Calculations_correction_06112024.pdf>.

always cover the opportunity cost of providing flexible synchronized reserves. Inflexible synchronized reserves, provided by resources that require hourly commitments due to run-time or staffing constraints, are not cleared with energy in the real-time market solution.[190] Instead, inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the day-ahead energy market. The ASO considers energy market price forecasts, availability of resources for flexible synchronized reserves, and regulation requirements to estimate the costs and benefits of using a resource for inflexible synchronized reserves. The ASO selected inflexible reserves are a fixed input to RT SCED, which clears the balance of the requirement with flexible synchronized reserves.

Nonsynchronized reserves and offline secondary reserves are cleared with every real-time energy market solution. The energy commitment decisions to keep the resources offline have already been made when the RT SCED clears the five-minute reserves markets. Therefore, offline reserves have no lost opportunity cost. They will not be called on for energy during the market interval for which they are assigned as offline resources.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which uses the RT SCED solution as an input. The LPC includes fast start pricing logic and system marginal price caps, so the final prices can be inconsistent with the marginal cost of the resources that clear regulation and reserves.

Section 10 Recommendations

Reserve Markets

- The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and automatically respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted 2024.)
- The MMU recommends that PJM replace the Mid-Atlantic Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Partially adopted 2022.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the unit repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the synchronized reserve shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM immediately remove the 30 percent increase to the synchronized reserve reliability requirement. (Priority: High. First reported 2024. Status: Not adopted.)

Regulation Market

- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. First reported 2023. Status: Not adopted.)[191]
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed

190 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Reserve Market Clearing, Rev. 134 (Apr. 23, 2025).

191 PJM filed proposed changes to the regulation market with the FERC on April 16, 2024, (Regulation Market Design Filing," Docket No. ER24-1772-000). The Commission Order on June 17, 2024 accepted the PJM Proposal as filed. PJM will implement the changes to the regulation market in two phases. Phase 1, scheduled to be implemented on October 1, 2025, will result in a single signal, bidirectional market with one clearing price that eliminates the need for an MBF. Phase 1 will eliminate RegA and RegD dual offers. Phase 1 will reduce the regulation commitment period from a 60-minute commitment to a 30-minute commitment. In Phase 1 the lost opportunity cost calculation used in the regulation market will be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule.

from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)[192]

- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.)[193]
- The MMU recommends that the current calculation of the performance score (based on precision, delay and correlation metrics) be replaced with the current calculation of the precision score. (Priority: Medium. First reported 2023. Status: Not adopted.).
- The MMU recommends that the regulation market commitment period be reduced from a 60-minute commitment to a 30-minute commitment. (Priority: Medium. First reported 2023. Status: Not adopted.).[194]
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[195] FERC rejected.)[196]
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[197]
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW. (Priority: Medium. First reported 2022. Status: Not adopted.)[198]
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[199]
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.)[200]

Frequency Response, Reactive, and Black Start

- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Partially adopted.)
- The MMU recommends that all data necessary to perform the generator primary frequency response evaluation be saved by PJM so that the test

192 See *id.*
193 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
194 See *id.*
195 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
196 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
197 See *id.*
198 In Phase 1 the ramp rate limited desired MW output will be used in the regulation uplift calculation. The MMU does not agree with how this change will be implemented and will be reviewing the market results in Phase 1.
199 See *id.*
200 See *id.*

can be replicated. (Priority: Medium. First reported 2023. Status: Not adopted.)

- The MMU recommends that PJM maintain a full list of all units subject to the Primary Frequency Response generator requirements. (Priority: Medium. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that PJM develop the metric(s) necessary to objectively evaluate each unit's performance during primary frequency response events. (Priority: Medium. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that PJM create the necessary tariff/manual language to properly enforce compliance with the NERC mandated Primary Frequency Response generator requirements. (Priority: Medium. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in PJM markets. (Priority: Medium. First reported 2016. Status: Adopted 2024.)[201]
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.95 power factor included in the voltage schedule in Interconnection Service Agreements. (Priority: Medium. First reported 2018. Status: Not adopted.)[202]
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019. Status: Not adopted.)[203]
- The MMU recommends that, if payments for reactive are continued, Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. (Priority: Medium. First reported 2020. Status: Not adopted.)[204]
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. Black start units should be required to commit to providing black start service for the life of the unit. CRF rates effective January 20, 2025, should reflect 100 percent bonus depreciation.[205] (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely zonal basis and that the costs of black start service be shared on an equal per MWh basis across the region. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that the Reliability Backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources. (Priority: High. First reported Q2, 2025. Status: Not adopted.)

Section 10 Conclusion

The October 1, 2022, changes to the reserve markets included a synchronized reserve must offer requirement applicable to all generation capacity resources. This resulted in an increase in available supply. Combined with the removal of the $7.50 per MWh margin and the invalid variable operations and maintenance cost, supply and demand logic predicts lower prices, which occurred in 2022, except during Winter Storm Elliott. This is evidence of market efficiency. With the elimination of tier 1 reserves, the total reserve market clearing price credits, while based on lower prices, are paid to a larger

201 On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM. On January 28, 2025, PJM submitted a compliance filing to implement Order No. 904 ("Compliance Filing") that proposed a transition mechanism lasting through May 31, 2026. See Docket No. ER25-1073. This recommendation will be implemented effective June 1, 2026.
202 *Id.* FERC Order No. 904 eliminates payments for reactive capability. When Order 904 is in effect, which is planned for June 1, 2026, this recommendation will be withdrawn as no longer relevant.
203 *Id.*
204 *Id.*
205 OBBA § 70301(b)(3).

MW quantity. Prices have been higher since PJM increased the demand for reserves in May 2023.

The new reserve market design has been called into question by PJM based on a slow response during synchronized reserve events. In all cases, other than during Winter Storm Elliott, the ACE recovered within the required time frame. No reliability problems have occurred. While the total response met the needs of the system, PJM responded to the poor performance of individual units by unilaterally and inappropriately increasing reserve requirements. This increase shifts the burden of poor resource performance from the resources themselves to customers, clearing more reserves instead of directly dealing with the causes of poor performance. These increases in reserve requirements were the primary cause of higher reserve prices in 2023, 2024, and the first nine months of 2025, including 35 intervals of shortage pricing in May 2023 and several intervals of shortage pricing during spin events in 2024 and the first nine months of 2025, even while reserve markets cleared over 1,000 MW more than what was normally cleared in the months and years prior.

The data on synchronized reserve event recovery do not support the conclusion that there was or is a need to increase the demand for reserves. The focus should be on correcting issues related to the responses of individual units rather than increasing demand.

Significant communications technology and modelling issues when calling resources during spinning events result in slow response. While PJM now calculates reserve offer MW for the majority of resource types, a resource's cleared reserve MW are based on a resource's energy output at the end of a scheduling interval. If a unit is still moving when an event is called, such as near the beginning of a scheduling interval, it may or may not be able to achieve its scheduled output. Likewise, a unit that is decreasing output to create more headroom might not be able to immediately increase output when an event is called.

Although PJM now augments a resource's economic basepoint with its dispatched reserve MW during a spin event, PJM does not require resources to be able to receive this signal. Many resources are still dispatched using phone calls, either from markets operation centers waiting for the PJM ALL-CALL or from MOCs themselves manually calling plant personnel.

Even if a unit is on AGC and receiving the augmented basepoint, depending on where that unit finds itself on its ramp rate curve, it might have to spend time coming off AGC or decreasing output in order to start ramping using power augmentation. Having a synchronized reserve maximum that is less than the unit's economic maximum can address this case, but it is the responsibility of that unit to request the exception.

The immediate solution is to improve the deployment of reserves in synchronized reserve events by requiring the capability to use an electronic signal for all synchronized reserves and the actual use of the signal. The archaic telephone communications technology has been a source of slow response times, such as markets operation centers waiting for the PJM ALL-CALL or manually calling unit personnel to deploy reserves. Phone calls are not an effective or efficient method for deploying resources for immediate response. The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and automatically respond to the notifications. On December 17, 2024, PJM partially adopted this recommendation by implementing an electronic deployment of reserves via an augmented dispatch signal, but PJM does not require that resources be able to receive this signal nor that the receiving units be able to follow the signal for deploying reserves. Further improvements in communications technology and requirements are necessary and PJM should pursue them immediately.

Along with changes to the communications and deployment process, PJM and the MMU have worked with generators to identify circumstances where reserves were not accurately measured based on the energy and reserve offer parameters. More broadly, the MMU's proposal is to buy the correct amount of reserves. No increase in demand is required. There has been no change in the need/demand for reserves. PJM ignored the supply side. The issue is that resources have not provided the reserves that were offered and paid for. With improved communications technology, instead of buying more MW of poorly performing reserves, PJM will be able to accurately recognize the actual supply of reserves and to more efficiently deploy them in synchronized reserve events. PJM should immediately remove the 30 percent increase to the synchronized reserve reliability requirement in place from May 2023 through September 2025.

The design of the current PJM Regulation Market is significantly flawed.[206] The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. The current market design allows regulation units that have the capability to provide both RegA and RegD MW to submit an offer for both signal types in the same market hour. However, the method of clearing the regulation market for an hour in which one or more units has a dual offer incorrectly accounts for the amount of RegD and the effective MW of the RegD that it clears. The result of the flaw is that the MBF in the clearing phase is incorrectly low compared to the MBF in the solution phase and the actual amount of effective MW procured is higher than the regulation requirement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. Under the current design, slower response RegA resources (generating units) must provide additional regulation to offset the negative impact of RegD resources (largely batteries) that are charging in the middle of a regulation hour. The ability of some resources to submit offers for both RegA and RegD (dual offers) results in inefficient high prices. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

PJM filed significant changes to the regulation market design on April 16, 2024, that were accepted as filed by order of June 17, 2024.[207] PJM will implement the changes to the regulation market in two phases. Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The proposed Phase 1 changes will eliminate many of the significant issues identified by the MMU that have resulted from a two product, two signal market design including the incorrect and inconsistent use and application of the MBF/MRTS.

The benefits of markets can be realized under the current approach to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power. However, there are significant issues with the PJM ancillary services markets.

The MMU concludes that the synchronized reserve market results were not competitive. The MMU concludes that the nonsynchronized reserve market results were not competitive. The MMU concludes that the secondary reserve market results were competitive. The MMU concludes that the regulation market results were not competitive, and the market design is significantly flawed.

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $848.0 million or 61.2 percent, from $1,385.8 million in the first nine months of 2024 to $2,233.8 million in the first nine months of 2025.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $985.1 million or 60.9 percent, from $1,618.5 million in the first nine months of 2024 to $2,603.6 million in the first nine months of 2025.
- **Balancing Congestion.** Negative balancing congestion costs increased by $137.1 million, from -$232.7 million in the first nine months of 2024 to -$369.8 million in the first nine months of 2025. Negative balancing

206 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
207 PJM, "Regulation Market Design Filing," Docket No. ER24-1772-000 (April 16, 2024).

explicit charges increased by $45.6 million, from -$148.0 million in the first nine months of 2024 to -$193.6 million in the first nine months of 2025.

- **Real-Time Congestion.** Real-time congestion costs increased by $1,143.6 million, from $1,659.3 million in the first nine months of 2024 to $2,802.9 million in the first nine months of 2025.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2025 ranged from $124.5 million in February to $608.9 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Pleasant View Line, Lenox – North Meshoppen Line, Pleasant View – Ashburn Line, the Goose Creek Transformer, and Ashburn – Goose Creek Line.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first nine months of 2025. The number of congestion event hours in the day-ahead energy market was about five times the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency decreased by 1.9 percent from 57,459 congestion event hours in the first nine months of 2024 to 56,377 congestion event hours in the first nine months of 2025.

  Real-time congestion frequency increased by 4.4 percent from 20,748 congestion event hours in the first nine months of 2024 to 21,659 congestion event hours in the first nine months of 2025.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on transformers and lines and increased on interfaces and flowgates.

  The Pleasant View Transformer was the largest contributor to congestion costs in the first nine months of 2025. With $286.5 million in total congestion costs, it accounted for 12.8 percent of the total PJM congestion costs in the first nine months of 2025.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. While CT pricing logic was officially discontinued, PJM continues to use a related logic to force inflexible units and demand response to be on the margin in both real time and day ahead. None of the PJM defined closed loop interfaces were binding in the first nine months of 2024 or 2025.
- **Zonal Congestion.** DOM had the highest zonal congestion costs among all control zones in the first nine months of 2025. DOM had $414.9 million in zonal congestion costs, comprised of $482.06 million in day-ahead congestion costs and -$67.1 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $400.4 million or 57.6 percent, from $695.2 million in the first nine months of 2024 to $1,095.5 million in the first nine months of 2025. The loss MWh in PJM increased by 745.4 GWh or 6.2 percent, from 12,066.6 GWh in the first nine months of 2024 to 12,812.0 GWh in the first nine months of 2025. The loss component of real-time LMP in the first nine months of 2025 was $0.04, compared to $0.03 in the first nine months of 2024.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $404.2 million or 54.2 percent, from $745.3 million in the first nine months of 2024 to $1,149.5 million in the first nine months of 2025.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $3.8 million or 7.6 percent, from -$50.1 million in the first nine months of 2024 to -$53.9 million in the first nine months of 2025.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $146.7 million or 56.8 percent, from $258.5 million in the first nine months of 2024, to $405.2 million in the first nine months of 2025.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2025 ranged from $74.9 million in May to $222.8 million in January.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $253.4 million or 58.3 percent, from -$434.8 million in the first nine months of 2024 to -$688.2 million in the first nine months of 2025.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $255.5 million or 48.9 percent, from -$522.9 million in the first nine months of 2024 to -$778.5 million in the first nine months of 2025.
- **Balancing System Energy Costs.** Balancing system energy costs increased by $17.9 million or 22.7 percent, from $78.7 million in the first nine months of 2024 to $96.5 million in the first nine months of 2025.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first nine months of 2025 ranged from -$137.8 million in January to -$46.4 million in May.

Section 11 Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and defined capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion costs increased by $848.0 million or 61.2 percent, from $1,385.8 million in the first nine months of 2024 to $2,233.8 million in the first nine months of 2025.

Monthly total congestion costs ranged from $124.5 million in February to $608.9 million in July in the first nine months of 2025.

The current ARR/FTR design does not ensure that load receives the rights to all congestion revenues. The congestion offset provided by ARRs and self-scheduled FTRs in the first four months of the 2025/2026 planning period was 66.6 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first four months of the 2025/2026 planning period, using the rules effective for each planning period, was 68.7 percent. Load has received $5.4 billion less than load should have received from the 2011/2012 planning period through the first four months of the 2025/2026 planning period.

Overview: Section 12, Generation and Transmission Planning

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2025, PJM had a total installed capacity of 200,952.5 MW, of which 38,366.4 MW (19.1 percent) are coal fired steam units, 57,064.2 MW (28.4 percent) are combined cycle units and 33,452.6 MW (16.6 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 200,952.5 MW of installed capacity, 72,221.3 MW (35.9 percent) are from units older than 40 years, of which 30,814.3 MW (42.7 percent) are coal fired steam units, 255.0 MW (0.4 percent) are combined cycle units and 25,550.6 MW (35.4 percent) are nuclear units.

Generation Retirements[208]

- As of September 30, 2025, there were 64,079.0 MW of generation that have been, or are planned to be, retired between 2011 and 2030, of which 46,526.8 MW (72.6 percent) are coal fired steam units.
- In the first nine months of 2025, 981.8 MW of generation retired. The largest generator that retired in the first nine months of 2025 was the 410.0 MW Indian River 4 coal fired steam unit located in the DPL Zone. Of the 981.8 MW of generation that retired in the first nine months of 2025, 410.0 MW (41.8 percent) were located in the DPL Zone.

208 See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2025) <https://www.pjm.com/planning/service-requests/gen-deactivations>.

- As of September 30, 2025, there were 8,351.9 MW of generation that have requested retirement after September 30, 2025, of which 2,620.0 MW (31.4 percent) are located in the AEP Zone. Of the generation requesting retirement in the AEP Zone, 2,620.0 MW (100.0 percent) are coal fired steam units.

Generation Queue

New Service Requests Serial Process[209]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[210] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out serial processing method.[211] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The transition to the new queue process began on July 10, 2023.
- There were 8,190 generation request projects submitted in the new service request serial process queue from 1997 until the implementation of the new cycle process on July 10, 2023. As a result of the transition to the new services cycle process, 312 projects were moved to transition cycle 1 (TC1). There were 1,347 projects eligible to resubmit for evaluation in transition cycle 2 (TC2). Of those 1,347 eligible projects, 550 projects resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects did not resubmit, and were withdrawn from the queue. There were 1,070 projects initially entered into the AH2 queue and beyond. Those 1,070 projects are now considered invalid and have been removed from the queue. As a result of the transition to the cycle process, the 8,190 projects in the serial process queue have been reduced to 5,461 projects. Projects that will be evaluated in TC1 and TC2, and those projects no longer eligible to be evaluated in the serial process have been removed from the new service requests serial process metrics. New service requests cycle process metrics are reported separately from the serial process metrics.
- As of September 30, 2025, a total of 43,634.4 MW, on an energy basis, were in generation request serial service queues in the status of active, under construction or suspended.[212] Based on historical completion rates, 23,288.8 MW (53.4 percent), on an energy basis, of new generation in the queue are expected to go into service. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.
- Of the 4,158.8 MW, on an energy basis, of combined cycle projects in the serial queue, 2,958.5 MW (71.1 percent) are expected to go in service based on historical completion rates as of September 30, 2025.
- Of the 3,426.1 MW, on an energy basis, of battery projects in the serial queue, only 931.2 MW (27.2 percent) are expected to go in service based on historical completion rates as of September 30, 2025.
- Of the 34,851.8 MW, on an energy basis, of renewable projects in the serial queue, 18,564.5 MW (53.3 percent) are expected to go in service based on historical completion rates as of September 30, 2025.
- Of the 3,949.1 MW, on a capacity basis that requested CIRs, of combined cycle projects requested in the generation serial queues in the status of active, under construction or suspended, 2,777.1 MW (70.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction,[213] the 3,949.1 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,055.1 MW of capacity (52.0 percent of the total requested capacity).[214]

209 See PJM. Planning. "Serial Service Request Status," (Accessed on September 30, 2025) <https://www.pjm.com/planning/service-requests/serial-service-request-status>.
210 See 181 FERC ¶ 61,162 (2022).
211 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.
212 Unless otherwise noted, the queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
213 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2027/2028 Base Residual Auction*, PJM Interconnection L.L.C. (August 1, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf>.
214 Unless otherwise noted, the ELCC derate adjusted MW are calculated using the 2027/2028 Base Residual Auction ELCC factors. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

- Of the 2,232.3 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation serial queues in the status of active, under construction or suspended, 161.5 MW (7.2 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 2,232.3 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 93.7 MW of capacity (4.2 percent of the total requested capacity).
- Of the 18,186.8 MW, on a capacity basis that requested CIRs, of renewable projects requested in the serial generation queues in the status of active, under construction or suspended, 9,797.0 MW (53.9 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 18,186.8 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 965.8 MW of capacity (5.3 percent of the total requested capacity).
- As of September 30, 2025, 25,603.7 MW of capacity requests (requested CIRs) were in the generation serial queues in the status of active, under construction or suspended. Based on historical completion rates, 13,565.8 MW (53.0 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 25,603.7 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 3,631.5 MW of capacity (14.2 percent of the total requested capacity).
- As of September 30, 2025, 5,461 projects, representing 609,132.6 MW, have entered the serial queue process since its inception. Of those, 1,267 projects, representing 93,774.7 MW (15.4 percent of the MW), went into service. Of the projects that entered the serial queue process, 3,734 projects, representing 471,723.5 MW (77.4 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed, by taking up queue positions, increasing interconnection costs and creating uncertainty.
- In the first nine months of 2025, 2,117.1 MW from the serial queue went into service. Of the 2,117.1 MW that went in service, 1,883.2 MW (89.0 percent) were solar units, 150.0 MW (7.1 percent) were solar + storage units, 54.9 MW (2.6 percent) were wind units and 29.0 MW (1.3 percent) were coal fired steam units.
- The number of serial queue entries increased during the past several years, primarily renewable projects. Of the 2,809 projects that entered the serial queue from January 1, 2015, through July 10, 2023, 2,062 projects (73.4 percent) were renewable. Of the 690 projects that entered the serial queue in 2020, 545 projects (79.0 percent) were renewable. Renewable projects make up 85.9 percent of all projects in the serial queue and account for 79.9 percent of the nameplate MW currently active, suspended or under construction in the serial queue as of September 30, 2025.
- On September 30, 2025, 31,841.9 MW, on an energy basis, were in generation request serial queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Of the 31,841.9 MW, 12,683.3 MW (39.8 percent) had not begun construction, 9,873.5 MW (31.0 percent) had begun construction, but are now suspended, and 9,285.2 MW (29.2 percent) are currently under construction. Reaching the final milestone required prior to construction does not mean a project will immediately begin construction or even that it necessarily will ever begin construction.

New Service Requests Cycle Process[215]

Transition Cycle 1 (TC1)

- Transition cycle 1 (TC1) is comprised of 312 proposed generation projects. Those projects make up 40,650.2 MW. On September 30, 2025, all projects in TC1 were either in the status of active or were withdrawn from the cycle. Of the 40,650.2 MW in TC1, 17,873.8 MW (44.0 percent) were active and 22,776.3 MW (56.0 percent) were withdrawn.

215 See PJM. Planning. "Cycle Service Request Status," (Accessed on September 30, 2025) <https://www.pjm.com/planning/m/cycle-service-request-status>.

- On September 30, 2025, there were 17,873.8 MW, on an energy basis, of which 8,854.3 MW are on a capacity basis that requested CIRs, in TC1 in the status of active.
- Of the 8,854.3 MW, on a capacity basis that requested CIRs in TC1 in the status of active, 2,152.8 MW (24.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 5,082.0 MW, on a capacity basis that requested CIRs, of solar projects requested in TC1 in the status of active, 406.6 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 1,565.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC1 in the status of active, 907.9 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 6,720.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC1 in the status of active, 897.9 MW (13.4 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Transition Cycle 2 (TC2) and Reliability Resource Initiative (RRI)

- On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[216] On February 11, 2025, the Commission approved the RRI tariff modifications.[217] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period.
- PJM received 97 applications (28.6 GW) of RRI projects during the RRI application window. Of these projects, 48 involve uprates, in which existing resources are modified to increase the economic maximum generation capability, and 49 propose building new generation. PJM reviewed the submitted RRI projects using the Commission approved scoring criteria, and approved 51 projects (11,577.4 MW).[218] On September 30, 2025, all RRI projects were either in the status of active or withdrawn from the cycle. Of the 11,577.4 MW of approved RRI projects, 10,938.4 MW (94.5 percent) were active and 639.0 MW (5.5 percent) were withdrawn.
- Transition cycle 2 (TC2) is comprised of 647 proposed generation projects. TC2 includes 550 projects submitted during the TC2 window, and 97 projects submitted through the RRI window. Those projects make up 78,329.4 MW. On September 30, 2025, all projects in TC2 were either in the status of active or were withdrawn from the cycle. Of the 78,329.4 MW in TC2, 45,977.6 MW (58.7 percent) were active and 32,351.8 MW (41.3 percent) were withdrawn.
- On September 30, 2025, there were 45,977.6 MW, on an energy basis, of which 32,120.8 MW are on a capacity basis that requested CIRs, in TC2 in the status of active.
- Of the 32,120.8 MW, on a capacity basis that requested CIRs in TC2 in the status of active, 14,167.2 MW (44.1 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 10,051.8 MW, on a capacity basis that requested CIRs, of solar projects requested in TC2 in the status of active, 804.1 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 7,400.0 MW, on a capacity basis that requested CIRs, of battery projects requested in TC2 in the status of active, 4,292.0 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 13,167.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC2 in the status of active, 1,146.4 MW (8.7 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

216 See *PJM Interconnection LLC*. Docket No. ER25-712 (December 13, 2024).
217 190 FERC ¶ 61,084 (February 11, 2025).
218 The RRI proposal was to select the top 50 projects using the approved scoring criteria. The implemented scoring criteria resulted in a tie for the 50th project. This resulted in PJM selecting 51 projects as part of the RRI process.

Cycle Process Totals[219]

- On September 30, 2025, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 118,979.6 MW. On September 30, 2025, all projects in the cycle process queues were either in the status of active or were withdrawn. Of the 118,979.6 MW in the cycle process queues, 63,851.5 MW (53.7 percent) were active and 55,128.1 MW (46.3 percent) were withdrawn.
- On September 30, 2025, there were 63,851.5 MW, on an energy basis, of which 40,975.1 MW are on a capacity basis that requested CIRs, in cycle process queues in the status of active.
- Of the 40,975.1 MW, on a capacity basis that requested CIRs in the cycle process queues in the status of active, 16,320.0 MW (39.8 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 15,133.8 MW, on a capacity basis that requested CIRs, of solar projects requested in cycle process queues in the status of active, 1,210.7 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 8,965.3 MW, on a capacity basis that requested CIRs, of battery projects requested in cycle process queues in the status of active or under construction, 5,199.9 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 19,887.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in cycle process queues in the status of active or under construction, 2,044.2 MW (10.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

219 As of September 30, 2025, the cycle process totals include those projects included in TC1 and TC2.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. If done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis would include the total net change in production costs and would not include congestion. In addition, PJM's benefit/cost analysis includes only the decreases in costs to load and ignores the increases in costs to load associated with market efficiency projects.
- Through September 30, 2025, PJM has completed five market efficiency cycles under Order No. 1000.[220] PJM delayed the opening of the 2022/2023 Long-Term Window until the reliability violations for the 2022 Window 3 were addressed. In January 2024, PJM completed updating the 2022/2023 market efficiency base case to include the solution selected from the 2022 Window 3. No flowgates experienced historical congestion that required an open window. PJM will continue to analyze the congestion patterns as part of the 2024/25 Market Efficiency cycle. In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. PJM posted an updated 2024/2025 base case in July 2024, and requested stakeholder feedback by August 31, 2024. As of June 5, 2025, PJM completed its production cost simulations for the 2025 study year using existing topology and production cost simulations using the RTEP topology. As of June 5, 2025, PJM completed its production cost simulation of the 2029 study year with RTEP topology. The long term market efficiency window opened on April 11, 2025, and closed on June 10, 2025. The next step in the annual RTEP project acceleration process (RTEP market efficiency process) is to identify the specific RTEP reliability projects that reduce congestion costs in the simulation results.[221] The chosen projects will be presented in the fourth quarter of 2025.

220 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).
221 See PJM Operating Agreement, Section 1.5.7 (b) and (c).

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.
- The simultaneous use for joint projects of an incorrectly defined benefit/cost method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass a correctly defined benefit/cost test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

PJM MISO Interregional Transfer Capability Study (ITCS)

- PJM and MISO developed the Interregional Transfer Capability Study (ITCS) to help identify potential transmission projects that could incrementally improve the systems' ability to mitigate constraints, improve market efficiency, respond to extreme weather and increase interregional transfer capability.

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[222] Supplemental projects are exempt from competition.
- The average number of supplemental projects in each expected in service year increased by 1,110.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 242 for years 2008 through 2025 (post Order 890).[223]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build the project. Under the current approach, end of life projects are excluded from the RTEP process and exempt from competition.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews proposals to improve transmission reliability in PJM and between PJM and neighboring regions. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[224] In the first nine months of 2025, the PJM Board approved $7.9 billion in upgrades. As of September 30, 2025, the PJM Board has approved $58.0 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives, and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.

222 See PJM. "Transmission Construction Status," (Accessed on September 30, 2025) <https://www.pjm.com/planning/m/project-construction>.

223 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

224 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system, financed and built by market participants, that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2025, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When a reportable transmission facility needs to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[225]
- There were 11,918 transmission outage requests submitted in the first four months of the 2025/2026 planning period. Of the requested outages, 66.6 percent were planned for less than or equal to five days and 13.6 percent were planned for greater than 30 days. Of the requested outages, 31.0 percent were late according to the rules in PJM's Manual 3.

225 See "PJM Manual 03: Transmission Operations," Rev. 68 (May 21, 2025).

Section 12 Recommendations

Generation Retirements

- The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors or to exercise market power by requiring high payments for CIRs.[226] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. PJM does not update this data. (Priority: High. First reported 2023. Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: High. First reported 2024. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as an expedited process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent

226 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

gaming.[227] (Priority: Medium. First reported 2013. Status: Partially adopted.)

- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[228] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all changes in production costs but not congestion costs, including increased costs to load and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. The MMU also recommends that, if the market efficiency process is retained, market efficiency projects that fail to meet PJM benefit/cost criteria in a Schedule 6 annual reevaluation, prior to construction commencing or prior to state approval, be canceled and removed from further consideration. (Priority: Medium. First reported 2018. Status: Not adopted.)

227 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).
228 Ibid.

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to require competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[229]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[230]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)

229 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).
230 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

- The MMU recommends that PJM incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and require competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to require competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax allocation method is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the transmission facilities.[231] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Partially adopted.)
- The MMU recommends that all PJM transmission owners investigate the applicability and potential cost savings of Grid Enhancing Technology (GET) and that all PJM transmission owners implement cost effective GET, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2024. Status: Not adopted.)
- The MMU recommends that the implementation of Grid Enhancing Technology (GET) be opened to competition from third parties, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2024. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages. (Priority: Low. First reported 2014. Status: Not adopted.)

231 See *2015 State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

- The MMU recommends that PJM draft a definition of the economic and physical congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date, based on those options. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 12 Conclusion

The goal of the PJM market design should be to enhance competition and to ensure that competition is the core element of all PJM markets. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. When generating units retire or load increases, there is no market mechanism in place that would require or even permit direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to require competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The MMU recognizes that the Commission has issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Order No. 1000 removed the right of first refusal (ROFR) for transmission projects for incumbent transmission owners except for the case of supplemental projects. This created an incentive for incumbent transmission owners to designate projects as supplemental projects to avoid the Order No. 1000 competitive provisions. Two PJM states, Indiana and Michigan, have passed laws that provide ROFR to incumbent utilities/transmission owners.[232] [233]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented. All PJM Transmission Owners should be required to immediately adopt current dynamic line rating (DLR) methods for all transmission facilities, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC.

Given the slow pace of adoption by Transmission Owners of Grid Enhancing Technologies (GETs), PJM and the Commission should introduce rules that would allow third parties to propose adding GETs to the transmission system,

232 See IN Code § 8-1-38-9, effective 7/1/2023. Applies to transmission facilities approved for construction through an RTO planning process. Incumbent Transmission Owner must exercise within 90 days.
233 See MCL §460.593, effective 12/17/2021. Applies to regionally cost shared transmission lines included in a plan adopted by a recognized planning authority. Must be exercised by the incumbent (s) within 90 days after plan is adopted/approved.

subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The third parties would be compensated in the same way that TOs would be compensated for comparable investments.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

It would be antithetical to competition to permit transmission owners to own black start units under the backstop rules, to own batteries (storage as a transmission asset) or to permit transmission owners to build new generation, all under the antiquated cost of service regulation rules that were displaced by more efficient competitive markets. Such an approach would undermine competitive markets and require market projects built with investors' capital at risk to compete with subsidized resources.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to require competition to build the project. If there is no defined need for a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

Managing the generation queues is a complex process. The PJM queue evaluation process will be significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[234] [235] The new rules include significant modifications to the interconnection process designed to address some of the key underlying issues and significantly improve the efficiency of the process. These modifications include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation. The new process should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

While the changes in the queue process will clearly improve the process, the MMU's recommendations related to the queue process will remain until the new process is fully in place and it can be evaluated. The impact of the modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. The impact of these aspects of the revised interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. Initial results from the transition cycles have shown that developers are withdrawing their projects at the specified decision points, which is helping to remove speculative projects from the queue process sooner. Whether the new cycle process will result in enough new dispatchable and renewable generation to meet system needs cannot be determined until after a full cycle has been completed, projects go in service and completion rates can be evaluated. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed

234 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
235 See 181 FERC ¶ 61,162 (2022).

include the ownership rights to CIRs and whether transmission owners should perform interconnection studies.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

On January 31, 2025, PJM submitted revisions to the PJM Tariff to expedite the transfer of CIRs from deactivating generating resources to new replacement resources.[236] The Market Monitor filed opposing comments.[237] The Commission rejected the filing, finding (i) "that the lack of a maximum time limit for Commercial Operation Date extensions, which introduces the opportunity to delay commercial operation for an indefinite period of time, would result in a generator replacement process that does not promote the efficient interconnection of new resources;" and (ii) "because the unrestricted opportunity for a Replacement Generation Resource Project Developer to significantly delay commercial operation may result in CIRs and associated transmission capacity dedicated to accommodate the Replacement Generation Resource's operation going unused."[238] PJM has filed a new proposal for rule transferring CIRs to replacement resources which attempts to correct the deficiencies identified by FERC but continues to be flawed. [239]

The suggestion that generation owners should be permitted to avoid the queue process and directly transfer the generation CIRs to an affiliate or directly sell the CIRs to an unaffiliated entity should be rejected.[240] [241] This proposed approach is about creating a process to maximize the value of existing CIRs to incumbent generators and not about facilitating the efficient replacement of retiring resources. In effect, this approach, if adopted by the large number of retiring units, would create a chaotic, bilateral private queue process that would create market power and facilitate the exercise of market power in the sale of CIRs by incumbent generators. In effect the proposed approach would replace a significant part of the recently redesigned PJM queue process. The proposed continuation of retention of CIRs by incumbent generators creates the potential for delays of up to a year and the proponents have proposed the option to request further delays. This approach would inappropriately delegate the authority from PJM to the incumbent generator to choose the new resource based on highest offer for CIRs rather than based on PJM defined system reliability needs. There would be no requirement to even be a capacity resource and there would be no requirement to offer the capacity into the capacity market. After the entire process, the contribution to PJM reliability could be zero. PJM's recently proposed expedited process for addressing reliability needs (RRI) is preferable and should be considered as the preferred alternative to the proposed approach from the Planning Committee stakeholder process.

The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. Rules should be developed to permit PJM to advance projects in the queue if they would resolve immediate reliability issues that result, for example, from unit retirements. The rules should be consistent with the flexibility included in the new queue process but add the option for PJM to expedite the interconnection and commercial operation of projects in the queue that

236 See PJM Interconnection, L.L.C., Docket No. ER25-1128 (January 31, 2025).
237 See Comments of the Independent Market Monitor for PJM, Docket No. ER25-1128-000 (February 21, 2025).
238 192 FERC ¶ 61,137 at PP 38–39 (2025).
239 *See PJM Interconnection, L.L.C.*, Docket No. ER26-403-000 (October 31, 2025).

240 See PJM. "*Enhancing Capacity Interconnection Rights (CIR) Transfer Efficiency: Problem / Opportunity Statement*," <https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230731/20230731-item-08b---enhancing-capacity-interconnection-rights---cir---transfer-efficiency-problem-statement.ashx>.
241 On April 30, 2024, the CIR Transfer Efficiency issue was transferred from the Interconnection Process Subcommittee (IPS) to the Planning Committee (PC).

would address identified reliability issues, consistent with the standing of the projects in the queue.

The PJM queue process should continue to define available and needed CIRs for all capacity queue projects. CIRs from retiring units should be made available to the next resource in the queue that can use them, on the retirement date of the retiring resource. Generation owners do not have property rights in CIRs. The value of CIRs is a result of the entire transmission system which has been paid for by customers and other generators. The value of CIRs is a result of the existence of a network and is not a result solely or even primarily of the investment that may or may not have been required in order to get CIRs. The cost of CIRs is part of project costs included in generation owners' investment decisions like any other project cost and subject to the same risk and reward structure. Open access to the transmission system by new resources should not be limited by claims to own the access rights by retiring units. In addition, the proposal to bypass the PJM interconnection process with a private, bilateral process ignores the fact that if the new resource is a renewable resource or a storage resource, the new resource does not have a capacity market must offer requirement. The PJM interconnection process could be bypassed, CIRs transferred and then the resource does not offer into the capacity market. In that case, scarce CIRs will be withheld by a generator who does not provide capacity and customers have to pay for an additional capacity resource instead.

The fundamental purpose of the queue process is to provide open access to the grid for supply resources. More specifically, the fundamental purpose of the queue process for capacity resources is to provide open access to the grid and to ensure that the energy from capacity resources is deliverable so that capacity resources can meet their must offer obligations in the energy market and provide reliable energy supply during all conditions. In order to ensure that open access, all capacity resources should be required to have a must offer obligation in the capacity market. If they do not, such resources are effectively withholding access to the grid from capacity resources that would take on a must offer obligation in the capacity market. The result creates market power for the resources with no must offer obligation, noncompetitively limits access to the grid, increases capacity market prices above the competitive level, and creates uncertainty and unpredictable volatility in the capacity market.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current benefit/cost analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an incorrectly defined cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO transmission projects to PJM participants and in some cases approval of projects that do not pass a correctly defined benefit/cost test.

If it is retained, there are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. The current benefit/cost analysis explicitly and incorrectly ignores the increased costs to load in zones that results from an RTEP project when calculating the energy market benefits. All increases and decreases in costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the benefit/cost analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the benefit/cost analysis.

Recent proposals to use storage as a transmission asset (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. Storage is a market asset and should not be owned by transmission owners. PJM should not be evaluating SATA at all without a decision from FERC that SATA is allowable in PJM. At present it is not allowed.

A significant flaw in PJM's benefit/cost analysis is that projected benefits are based on load forecasts which are currently dominated by projected large data center loads that are not verified by PJM and cannot be verified by PJM. That creates a bias towards finding transmission projects beneficial despite the fact that data center loads are imposing transmission costs on other customers as a result.

There are currently no market incentives for transmission owners to plan, submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the day-ahead energy market and that have large and unnecessary impacts on the PJM energy market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear and expanded definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules. PJM Manual 38 currently defines congestion resulting from a transmission outage as an overload on transmission facilities rather than using the general economic definition of congestion resulting from out of merit generation to control constraints. PJM does not currently evaluate the economic impact of congestion when reviewing proposed transmission outages.[242]

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. PJM's analysis of expected congestion did not highlight the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion until after there were significant disruptions and congestion.

As an example of the complexities of defining the benefits of transmission investments, the reduction in congestion is frequently and incorrectly cited as a metric of benefits. Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. The correct metric is the total net change in production costs.

There is not a secular trend towards increasing congestion in PJM. Congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs.

242 PJM, "Manual 38: Operations Planning," Rev. 19 (January 23, 2025) at 19-20.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission to address a specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual transmission investment on future congestion. It is possible, for example, that congestion occurring during a period of a few days in the winter as a result of very high fuel prices, significantly increases the reported level of congestion for the entire year. This has occurred in PJM. It would be a mistake to consider that level of congestion to be a signal to build transmission.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation, while only high cost generators are paid the high price at their bus and low cost generators are paid only the low price at their bus.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

For all these reasons, if done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis for transmission projects would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project.

The PJM Regional Transmission Expansion Plan (RTEP) successfully addresses the need for transmission investment to reliably meet load. Together with the requirement that new generation pay interconnection costs, the RTEP process has resulted in the appropriate level of new transmission investment in PJM. There is no evidence that the PJM planning process is not adequate to meet the requirements of the PJM markets. Additional transmission investment is not a panacea. Transmission investment is expensive and long lived and it is essential that transmission investments be carefully planned for clearly identified needs in order to ensure that power markets can continue to provide reliable service at a competitive price.

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[243] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. The correct term is Part V reliability service. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required in order to limit the duration of Part V service for individual units. It is essential that the deactivation provisions of the tariff be evaluated and modified. It is also essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. PJM should consider an expedited queue process for projects that could replace the retiring capacity including the immediate transfer of the retiring unit's CIRs to units in the queue in order to permit generation to compete as an alternative to the current transmission only approach.

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth from data centers. Dominion has presented 44 supplemental project requests to serve the increase in load through the summer of 2025. As part of the supplemental planning process, PJM performs a do no harm analysis. PJM identified the need for additional baseline reinforcements to support the load growth. These baseline reinforcements were addressed in the 2022 RTEP Window 3, when the PJM board approved $1.4 billion of necessary baseline upgrades specific to the Data Center Alley reinforcements.[244] These regional transmission costs were allocated according to Schedule 12 of PJM's Open Access Transmission Tariff (OATT), where costs are shared across all zones by a combination of load ratio share and distribution factor impacts. The transmission owners include these project costs in their base case, and all retail customers in the PJM footprint pay for those upgrade costs through increased energy bills. The cost allocation of the $1.4 billion in baseline upgrades are assigned to all retail customers and not solely to the customers requesting interconnection.

The high level of customer requests in Data Center Alley resulted in the need for significant baseline reliability upgrades. These costs were allocated per Schedule 12 of the PJM OATT. Not all customer requests result in reliability upgrades. Transmission upgrades for customer requests that are submitted through the supplemental planning process are allocated 100 percent to the zone where they are interconnecting. The transmission owner of that zone then includes those project costs in their rate base, and all retail customers in that zone pay those costs.

The Virginia case illustrates the imposition of transmission costs by data centers on other PJM customers. These additional transmission costs are in addition to the significant capacity market costs imposed on other customers by the actual and forecast addition of large data centers.

The main focus of PJM's planning requirements has been to ensure adequate transmission to allow for generation to reliably serve load. Historically, PJM has had enough excess generation to serve the forecasted load in the RTEP process. In recent years, due in part to the significant increase in load resulting from large load data center interconnection requests and an increase in thermal unit deactivations, meeting forecasted loads and reserves with existing generation has become an issue. In order to solve the RTEP study cases, PJM must make assumptions about the existing and future generation to include in the RTEP model based on the need to serve load. The RTEP analysis first includes all existing generation that is expected to remain in service for the year being studied. When the forecasted load exceeds the expected in service generation, the RTEP analysis includes future generation. Planned generators with a signed interconnection service agreement (ISA) or generation interconnection agreement (GIA), or that cleared a BRA, are included. When the PJM load in the RTEP analysis exceeds the sum of existing generation and generation with an executed final agreement, the RTEP analysis simply adds speculative new generation that is in its Phase 3 system impact study status to meet the load. If needed, additional generation (pre-GIA stage or with a suspended status)

243 OATT Part V §114.
244 See "*Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board*," December 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx>.

may be modeled (assumed) consistent with the procedures noted in Manual 14B.[245] [246] The RTEP analysis is not adequately coordinated with PJM markets analysis including the energy and capacity markets.

Overview: Section 13, FTRs and ARRs

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2025/2026 planning period ARRs were allocated to 1,560 individual participants, held by 130 parent companies, up from 1,523 individual parents, held by 126 parent companies in the 2024/2025 planning period. ARR ownership for the 2025/2026 planning period was unconcentrated with an HHI of 600, down from 610 for the 2024/2025 planning period.

Market Behavior

- **Self Scheduled FTRs.** For the 2025/2026 planning period, 25.9 percent of eligible ARRs were self scheduled as FTRs, up from 25.3 percent for the 2024/2025 planning period.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first four months of the 2025/2026 planning period, ARRs and self scheduled FTRs offset only 66.6 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $5.4 billion from the 2011/2012 planning period through the first four months of the 2025/2026 planning period. The cumulative offset for that period was only 68.7 percent of total congestion. If ARR holders had self scheduled all of their allocated FTRs as ARRs for the first four months of the 2025/2026 planning period, the ARR target allocations would have increased the offset from 66.6 percent to 98.7 percent of total congestion.

- **ARR Payments.** For the first four months of the 2025/2026 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $1,859.0 million, while PJM collected $2,088.2 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2024/2025 planning period, the ARR target allocations were $1,448.1 million while PJM collected $1,664.9 million from the combined Annual and the first four Monthly Balance of Planning Period FTR Auctions.

- **ARR.** For the first four months of the 2025/2026 planning period there was enough total day-ahead congestion to pay FTR target allocations. However, as a result of the monthly settlement logic for FTRs and ARRs, $22.6 million of FTR auction revenue over ARR target allocations was transferred from ARR holders (load) to FTR holders. In the 2024/2025 all $196.2 million of FTR auction revenue over ARR target allocations was transferred from ARR holders to FTR holders. Although PJM refers to this as a surplus, there is no such thing as surplus FTR auction revenue based on market logic. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason.

- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first four months of the 2025/2026 planning period, as a result of transmission capability being returned to service from outages included in the annual model, PJM allocated a total of 16,614.7 MW of residual ARRs, up 8,616.5 MW (a 107.7 percent increase) from 7,998.2 MW, with a total target allocation of $50.5 million, up $45.0 million (an 819.9 percent increase) from $5.5 million in the same period of the 2024/2025 planning period.

245 See "Review of 2025 RTEP Assumptions," presented at the January 7, 2025 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250107/20250107-item-11---2025-rtep-assumption.pdf>.
246 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).

- **ARR Deficiency.** In July 2025 there was not enough FTR auction revenue collected from the monthly FTR auction to pay the high target allocations from Residual ARRs. As a result, July ARR funding was deficient for the first time since ARRs were introduced. Deficient ARRs will be funded at the end of the planning period from surplus FTR revenues, if there is an FTR surplus, or through an uplift charge to FTR holders if there is not an FTR surplus.
- **ARR Reassignment for Retail Load Switching.** There were 16,509 MW of ARRs associated with $385.7 thousand of revenue that were reassigned for the first four months of the 2025/2026 planning period. There were 11,996 MW of ARRs associated with $184.3 thousand of revenue that were reassigned in the same period of the 2024/2025 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions includes auctions for each remaining month in the planning period.

Market Structure

- **Patterns of Ownership.**[247] For the Monthly Balance of Planning Period Auctions, financial entities purchased 96.4 of all prevailing and counter flow FTRs, including 95.3 percent of prevailing flow and 97.7 percent of counter flow FTRs for the first four months of the 2025/2026 planning period. Financial entities owned 88.7 percent of all prevailing and counter flow FTRs, including 82.5 percent of all prevailing flow FTRs and 95.7 percent of all counter flow FTRs during the first four months of the 2025/2026 planning period. Self scheduled FTRs account for 4.3 percent of all FTR held.
- **Market Concentration.** In the Monthly Balance of Planning Period Auctions for the first four months of the 2025/2026 planning period, ownership of cleared prevailing flow bids was unconcentrated in all periods. Ownership of cleared counter flow bids was unconcentrated in 47.6 percent of periods and moderately concentrated in 52.4 percent of periods.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the 2025/2028 Long Term FTR Auction, total participant FTR sell offers were 1,557,455 MW. In the 2025/2026 Annual FTR Auction, total participant FTR sell offers were 1,695,004 MW. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2025/2026 planning period, total participant FTR sell offers were 31,730,557 MW.
- **Buy Bids.** In the 2025/2028 Long Term FTR auction, total FTR buy bids were 6,729,000 MW, up 72.0 percent from 5,729,618 MW the previous long term auction. There were 6,658,483 MW of buy and self scheduled bids in the 2025/2026 Annual FTR Auction, up 39.6 percent from 4,770.381 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2025/2026 planning period were 48,912,396 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $1,312.2 thousand for the first four months of the 2025/2026 planning period, up 38.0 percent from $951.0 thousand from the same period of the2024/2025 planning period.
- **Credit.** There were no collateral defaults and two payment defaults in the first nine months of 2025.

Market Performance

- **Quantity.** In the 2025/2028 Long Term FTR Auction 923,869 MW (13.7 percent) of buy bids cleared and 168,852 MW (10.8 percent) of sell offers cleared. In the 2025/2026 Annual FTR Auction 1,324,299 MW (19.9 percent) of buy and self scheduled bids cleared, up 28.8 percent from the 2024/2025 Annual FTR Auction, and 183,410 MW (10.8 percent) of sell offers cleared, up 47.6 percent from the 2024/2025 Annual Auction. In the first four months of the 2025/2026 planning period, Monthly Balance of Planning Period FTR Auctions 8,010,114 MW (16.4 percent) of FTR buy

247 Beginning in the *2025 Quarterly State of the Market Report for PJM: January through March*, the MMU categorizes all participants owning FTRs in PJM as either physical or financial at an account level. In prior reports, participants were categorized as either physical or financial at an organization level.

bids cleared, up 54.9 percent from the the same period of the 2024/2025 planning period and 5,089,192 MW (16.0 percent) of FTR sell offers cleared, up 36.5 percent from the same period of the 2024/2025 planning period.

- **Price.** The weighted average buy bid FTR price in the 2025/2028 Long Term FTR Auction was $0.09 per MW, up from $0.07 from the 2024/2027 Long Term FTR Auction. The weighted average buy bid FTR price in the Annual FTR Auction for the 2025/2026 planning period was $0.50 per MW, up from $0.30 per MW in the 2024/2025 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods in the first four months of the 2025/2026 planning period was $0.36 per MWh, down from $0.42 in the 2024/2025 planning period.
- **Revenue.** The 2025/2028 Long Term FTR Auction generated $162.3 million of net revenue for all FTRs, up 58.2 percent from $102.6 million from the 2024/2027 Long Term FTR Auction. The 2025/2026 Annual FTR Auction generated $1,895.3 million in net revenue, up 28.5 percent from $1,475.3 million for the 2024/2025 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $39.9 million in the first four months of the 2025/2026 planning period, down 20.4 percent from $50.1 million in the same period of the 2024/2025 planning period.
- **"Revenue Adequacy."** For the first four months of the 2025/2026 planning period there was enough total day-ahead congestion revenue to pay FTR target allocations. However, as a result of the monthly settlement logic for FTRs and ARRs, $22.6 million of FTR auction revenue was transferred from ARR holders (load) to FTR holders, and FTRs were paid 100.0 percent of the target allocations for the first four months of the 2025/2026 planning period. Based on market logic, there is no such thing as surplus FTR auction revenue and there is no such thing as revenue inadequacy. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of buying the FTR. In the first four months of the 2025/2026 planning period, profits for all participants were $445.8 million, up from $351.8 million in profits in the same time period in the 2024/2025 planning period. In the first four months of the 2025/2026 planning period, physical entities received $93.0 million in profits on FTRs purchased directly (not self scheduled), up from $36.4 million profits in the same time period in the 2024/2025 planning period. Financial entities received $352.8 million in profits, up from $315.4 million profits in the same time period in the 2024/2025 planning period.

Section 13 Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion revenue that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions in allocated revenue as a contingency for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including both day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported 2022. Status: Not adopted.)[248]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

"Surplus"

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[249] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

248 If adopted, this recommendation would replace the next two recommendations.

249 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost to the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends that PJM's minimum credit requirements be reviewed and updated to appropriately reflect the risk created for the markets and other market participants. The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollars amounts in 2011 in FERC order 741 based on the specific market participation (FTRs or other). (Priority: Medium. New recommendation. Status: Not adopted.)

Section 13 Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in PJM's security constrained LMP market. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right should be to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the voluntary sale by load of their congestion revenue rights at terms defined by load, recognizing that load has property rights to congestion.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without the use of generation to load contract paths, and if the distortions subsequently introduced into the FTR design had not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives including so called revenue adequacy. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[250] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[251] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that actual congestion is the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

250 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
251 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 158 FERC ¶ 61,093 (2017).

A subsequent rule change was implemented that modified the allocation of what is termed surplus auction revenue to load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[252] ARR holders will only be allocated this surplus after FTRs are paid 100 percent of their target allocations. While this rule change increased the level of congestion revenues returned to load under some conditions, the rules do not recognize ARR holders' rights to all congestion revenue, and only improves congestion payouts to load when there is a surplus. There was no surplus for the 2020/2021 or 2021/2022 planning years. With this rule in effect for the 2021/2022 planning period, ARRs and self scheduled FTRs offset 31.6 percent of total congestion. There was surplus for the 2022/2023 and the 2023/2024 planning periods. However, FTR auction surplus revenues were taken from load and given to FTR holders because day-ahead congestion revenues were less than target allocations in the 2023/2024 planning period. For the 2024/2025 planning period, there was not enough congestion revenue to fund FTR target allocations and all FTR auction surplus revenues were taken from load and given to FTR holders. Based on market logic, there is no such thing as surplus FTR auction revenue. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason. ARRs and self scheduled FTRs offset only 66.6 percent of total congestion paid by load in the first four months of the 2025/2026 planning period. Load has been underpaid congestion revenues by $5.4 billion from the 2011/2012 planning period through the first four months of the 2025/2026 planning period. The cumulative offset for that period was only 68.7 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs is entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not actually built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant

252 163 FERC ¶ 61,165 (2018).

generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

PJM proposed, and on March 11, 2022, FERC accepted, an increase to Stage 1A ARR allocations from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL).[253] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior twelve month period, and NSPL is a network service customer's contribution to the highest daily zonal peak load in the prior twelve month period. PJM's new ARR allocation rules have increased Stage 1A rights at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's new ARR allocation rules have exacerbated the current misalignment between congestion property rights and the congestion paid by load.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the voluntary sale by load of their congestion revenue rights at terms defined by load.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other rights holders. In the case of a defaulting buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy and what generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that is credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with the auction clearing price for the 50 percent of the CRR that was sold to the third party. Depending on actual congestion and the price paid for a CRR, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly and/or more frequent.

253 See 178 FERC ¶ 61,170.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM management, and the PJM Board; participates in PJM stakeholder meetings and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Recommendation Priority

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

Recommendation Status

The MMU also tracks PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. Each recommendation includes a status. The status categories are:

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.
- **Withdrawn:** The MMU no longer makes the recommendation because it has become irrelevant or because it has been replaced by another recommendation.

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[6]

In this *2025 Quarterly State of the Market Report for PJM: January through September*, the MMU includes three new recommendations.

New Recommendations from Section 6, Demand Response

- The MMU recommends that DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 13, Financial Transmission Rights and Auction Revenue Rights

- The MMU recommends that PJM's minimum credit requirements be reviewed and updated to appropriately reflect the risk created for the markets and other market participants. The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollars amounts in 2011 in FERC order 741 based on the specific market participation (FTRs or other). (Priority: Medium. New recommendation. Status: Not adopted.)

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers per the PJM Operating Agreement not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Partially adopted 2023.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Partially adopted.)
- The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)[7]
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)

7 The real-time market formula for determining the lowest cost schedule is documented. The day-ahead market formula for determining the lowest cost schedule is not documented.

- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, that PJM commit all resources that fail the TPS test on their cost-based offers, that the Market Seller designate the cost-based offer if there is more than one, and that PJM implement this solution as soon as possible. (Priority: High. First reported Q3 2024. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)[8]

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage resources be subject to an enforceable ICAP must offer rule in the day-ahead and real-time energy markets that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, that gas generators be required to inform PJM about whether they have gas, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported 2022. Status: Not adopted.)

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[9]

8 The applicability of the FMU and AU adders is limited by the rule implemented in 2014 requiring that net revenues must fall below avoidable costs, but the possibility of FMU and AU adders is still part of the PJM Market Rules.

9 Flexible parameter standards are in place for combined cycle and combustion turbine resources when operating on a parameter limited schedule, but not for other schedules or generating technologies.

- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported 2022. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[10]
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.[11] (Priority: Low. First reported 2013. Status: Not adopted.)

10 PJM created a more transparent process for transmission constraint penalty factors and added it to the tariff in 2020. Policies on reductions in control limits and the duration of violations remain discretionary and undocumented in the PJM Market Rules.
11 This recommendation was the result of load shed events in September, 2013. For detailed discussion, please see *2013 Annual State of the Market Report for PJM*, Volume 2: Section 3 at 114 – 116.

- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[12] [13] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)

12 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

13 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and LPC and instead limit the sum of violated reserve constraint shadow prices that are included in the determination of LMP in LPC to $1,700 per MWh. While PJM no longer caps prices in RT SCED, PJM continues to apply a cap to the system marginal price in the pricing run (LPC) under fast start pricing. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. First reported 2021. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[14]
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch

14 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.

signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[15]

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

Section 4, Energy Uplift

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

15 The PJM Market Rules clarify that shortage case approval will be based on RT SCED, but does not address RT SCED case choice or load bias.

- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM require wind units to request CIRs based on the maximum output used in the ELCC calculation for wind units. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[16]

Section 5, Capacity Market

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, and imports.[17] [18] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market construct because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 delivery year. EE is not a capacity resource as defined in the tariff, and

16 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

17 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

18 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

there is no reason to continue to pay large subsidies to EE providers.[19] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[20]

- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs to intermittent resources that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[21]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. (Priority: High. First reported 2023. Status: Not adopted.)

19 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 37 (Dec. 18, 2024).
20 See 189 FERC ¶ 61,095 (2024).
21 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

Market Design and Parameters

- The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement in the 2022 Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as 1.5 times Net CONE, capped at Gross CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the gross CONE in ICAP terms for a CT to the gross CONE in UCAP terms be the ELCC based on winter ratings. (Priority: High. First reported 2024. Status: Adopted 2025.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model including transmission constraints inside LDAs. The market design should clear and pay units that are needed for reliability per PJM's transmission reliability analysis in order to forestall RMRs. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission

system inside and outside LDAs consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)[22]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)[23]
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that modifications to existing resources, including relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as

22 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

23 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[24]

- The MMU recommends that the RPM market power mitigation rules be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity for both new resources and existing resources. (Priority: Medium. First reported 2017. Status: Not adopted.)[25]
- The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[26] (Priority: High. First reported 2013. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage and associated performance penalty. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests

24 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

25 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

26 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

be limited, and that the ambient conditions under which the tests are performed be defined to reflect seasonal extreme conditions. (Priority: Medium. First reported 2022. Status: Not adopted.)

- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or subzonal, or defined combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from the current one quarter prior (See Table 5-29) to 12 months prior to an auction in which the unit will not be offered due to deactivation; and no less than 12 months prior to the date of deactivation (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends elimination of both the cost of service recovery rate option and the deactivation avoidable cost rate option for providing Part V reliability service (RMR), and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus a defined incentive. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that if units that are paid under Part V of the OATT (RMR) are included in the calculation of CETO and/or reliability in the relevant LDA, the capacity of the RMR resources should also be included in capacity market supply at zero cost, but without all the obligations of a capacity resource, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions, until a decision is made to build transmission as a replacement, and then should be included. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate timely and competitive entry into the PJM markets, open access to the transmission system and maintain the priority order defined by the queue process. (Priority: High. First reported 2023. Status: Not adopted.)

Section 6, Demand Response

- The MMU recommends that PJM report the response of emergency demand response resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the expected response to PJM dispatch. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that emergency demand response resources offering as supply in the capacity market be required to offer a guaranteed load drop (GLD) below their PLC to ensure that demand resources provide an identifiable MW resource to PJM when called. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends, as an alternative to including emergency demand response resources as supply in the capacity market, that demand resources have the option to be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for emergency demand response resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[27] (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for emergency demand response resources and price response demand resources be the same as the maximum offer for generation resources and that the same cost verification rules applied to generation resources apply to demand resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the emergency demand response resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that emergency demand response resources not be treated as emergency resources. The MMU recommends that emergency demand response resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Partially adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market prices is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if emergency demand response resources remain in the capacity market, a daily energy market must offer requirement apply to emergency demand response resources, comparable to the rule applicable to generation capacity resources.[28] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that emergency demand response resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of emergency demand response resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for

27 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

28 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that measurement and verification methods for all demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[29] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all emergency demand response resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that demand response testing be initiated by PJM with advance notice to CSPs identical to the actual lead time required in an emergency in order to accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that economic demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for emergency demand response resources clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[30])
- The MMU recommends that all demand resources register as Pre-Emergency and that the Emergency Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that the lead times for emergency demand response resources be shortened to 30 minutes with a one hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)

29 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

30 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

- The MMU recommends that energy efficiency resources (EE) not be included in the capacity market mechanism and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately. (Priority: Medium. First reported 2018. Status: Adopted 2024.)[31] [32]
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation. (Priority: Medium. First reported 2022. Status: Partially adopted.)
- The MMU recommends that the Commission require PJM to include in OATT Attachment M the explicit statement that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DERs. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level. (Priority: Medium. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that PJM revise the requirements for reporting expected real time energy load reductions by CSPs to PJM to improve the accuracy and usefulness to PJM's system operators. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI. The MMU recommends that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: Medium. New recommendation. Status: Not adopted.)

Section 7, Net Revenue

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical revenues that are scaled based on forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 8, Environmental and Renewables

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. (Priority: High. First reported 2010. Status: Not adopted.)

31 See 189 FERC ¶ 61,095.
32 Originally incorporated with auctions conducted in 2016 for the 2016/2017 Delivery Year and forward. The mechanics of the EE addback mechanism were modified beginning with the 2023/2024 Delivery Year.

- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that stationary emergency RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between

balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends eliminating the mechanism that defines FFE and M2M payments. These mechanisms are not consistent with markets and are not needed for efficient interface pricing. The MMU recommends that PJM file with the Commission to eliminate the FFE calculation and M2M payment of the PJM and MISO joint operating agreement. (Priority: Medium. First reported 2024. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends clear rules governing when PJM may recall capacity backed exports. (Priority: Medium. First reported 2010. Status: Partially adopted.)

Section 10, Ancillary Services

Reserve Markets

- The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and automatically respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted 2024.)
- The MMU recommends that PJM replace the Mid-Atlantic Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Partially adopted 2022.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the unit repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the synchronized reserve shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM immediately remove the 30 percent increase to the synchronized reserve reliability requirement. (Priority: High. First reported 2024. Status: Not adopted.)

Regulation Market

- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. First reported 2023. Status: Not adopted.)[33]
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)[34]
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.)[35]
- The MMU recommends that the current calculation of the performance score (based on precision, delay and correlation metrics) be replaced with the current calculation of the precision score. (Priority: Medium. First reported 2023. Status: Not adopted.).
- The MMU recommends that the regulation market commitment period be reduced from a 60-minute commitment to a 30-minute commitment. (Priority: Medium. First reported 2023. Status: Not adopted.).[36]
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[37] FERC rejected.)[38]

33 PJM filed proposed changes to the regulation market with the FERC on April 16, 2024, (Regulation Market Design Filing," Docket No. ER24-1772-000). The Commission Order on June 17, 2024 accepted the PJM Proposal as filed. PJM will implement the changes to the regulation market in two phases. Phase 1, scheduled to be implemented on October 1, 2025, will result in a single signal, bidirectional market with one clearing price that eliminates the need for an MBF. Phase 1 will eliminate RegA and RegD dual offers. Phase 1 will reduce the regulation commitment period from a 60-minute commitment to a 30-minute commitment. In Phase 1 the lost opportunity cost calculation used in the regulation market will be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule.
34 See *id.*
35 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
36 See *id.*
37 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
38 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[39]
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW. (Priority: Medium. First reported 2022. Status: Not adopted.)[40]
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[41]
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.)[42]

39 See *id.*
40 In Phase 1 the ramp rate limited desired MW output will be used in the regulation uplift calculation. The MMU does not agree with how this change will be implemented and will be reviewing the market results in Phase 1.
41 See *id.*
42 See *id.*

Frequency Response, Reactive, and Black Start

- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Partially adopted.)
- The MMU recommends that all data necessary to perform the generator primary frequency response evaluation be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM maintain a full list of all units subject to the Primary Frequency Response generator requirements. (Priority: Medium. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that PJM develop the metric(s) necessary to objectively evaluate each unit's performance during primary frequency response events. (Priority: Medium. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that PJM create the necessary tariff/manual language to properly enforce compliance with the NERC mandated Primary Frequency Response generator requirements. (Priority: Medium. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in PJM markets. (Priority: Medium. First reported 2016. Status: Adopted 2024.)[43]
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.95 power factor included in the voltage schedule in Interconnection Service Agreements. (Priority: Medium. First reported 2018. Status: Not adopted.)[44]
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019. Status: Not adopted.)[45]
- The MMU recommends that, if payments for reactive are continued, Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. (Priority: Medium. First reported 2020. Status: Not adopted.)[46]
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. Black start units should be required to commit to providing black start service for the life of the unit. CRF rates effective January 20, 2025, should reflect 100 percent bonus depreciation.[47] (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely zonal basis and that the costs of black start service be shared on an equal per MWh basis across the region. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that the Reliability Backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources. (Priority: High. First reported Q2, 2025. Status: Not adopted.)

43 On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM. On January 28, 2025, PJM submitted a compliance filing to implement Order No. 904 ("Compliance Filing") that proposed a transition mechanism lasting through May 31, 2026. See Docket No. ER25-1073. This recommendation will be implemented effective June 1, 2026.

44 *Id.* FERC Order No. 904 eliminates payments for reactive capability. When Order 904 is in effect, which is planned for June 1, 2026, this recommendation will be withdrawn as no longer relevant.

45 *Id.*

46 *Id.*

47 OBBA § 70301(b)(3).

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors or to exercise market power by requiring high payments for CIRs.[48] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. PJM does not update this data. (Priority: High. First reported 2023. Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: High. First reported 2024. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as an expedited process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[49] (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[50] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all changes in production costs but not congestion costs, including increased costs to load and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. The MMU

48 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

49 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).

50 Ibid.

also recommends that, if the market efficiency process is retained, market efficiency projects that fail to meet PJM benefit/cost criteria in a Schedule 6 annual reevaluation, prior to construction commencing or prior to state approval, be canceled and removed from further consideration. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to require competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[51]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[52]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and require competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to require competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax allocation method is implemented. The goal for such a process would be to ensure that the most rational and efficient approach

51 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

52 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)

- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the transmission facilities.[53] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Partially adopted.)
- The MMU recommends that all PJM transmission owners investigate the applicability and potential cost savings of Grid Enhancing Technology (GET) and that all PJM transmission owners implement cost effective GET, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2024. Status: Not adopted.)
- The MMU recommends that the implementation of Grid Enhancing Technology (GET) be opened to competition from third parties, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2024. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a definition of the economic and physical congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date, based on those options. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 13, FTRs and ARRs

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion revenue that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)

53 See *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions in allocated revenue as a contingency for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including both day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported 2022. Status: Not adopted.)[54]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)

54 If adopted, this recommendation would replace the next two recommendations.

- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

"Surplus"

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[55] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)

55 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost to the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends that PJM's minimum credit requirements be reviewed and updated to appropriately reflect the risk created for the markets and other market participants. The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollars amounts in 2011 in FERC order 741 based on the specific market participation (FTRs or other). (Priority: Medium. New recommendation. Status: Not adopted.)

Energy Market

The PJM energy market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2025.

Table 3-1 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on 94.1 percent of the days in the first nine months of 2025. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first nine months of 2025 was, on average, unconcentrated by FERC HHI standards. The average HHI was 686 with a minimum of 511 and a maximum of 988. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was unconcentrated on average. The peaking segment of the supply curve was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. Transmission constraints create the potential for the exercise of local market power. The goal of PJM's application of the three pivotal supplier test is to identify local market power and offer cap to competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their

marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.

- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in price formation, undermine market efficiency in the energy market. The implementation of fast start pricing on September 1, 2021, undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.
- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.[1] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[2] In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed, but, so far, PJM and FERC have failed to address them.[4] [5] [6] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

1 OATT Attachment M (PJM Market Monitoring Plan).
2 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).
3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
4 175 FERC ¶ 61,231 (2021).
5 185 FERC ¶ 61,158 (2023).
6 189 FERC ¶ 61,060 (2024).

Overview

Supply and Demand

Market Structure

- **Supply.** In the first nine months of 2025, 2,756 MW of new resources were added in the energy market, and 982 MW of resources were retired.
- The real-time hourly on peak average offered supply in the first nine months of 2025 increased by 1.4 percent, from the first nine months of 2024, from 140,934 MWh to 142,851 MWh.
- The day-ahead hourly average offered supply in the first nine months of 2025 decreased by 1.5 percent, from the first nine months of 2024, from 153,603 MWh to 151,275 MWh.
- The real-time hourly average cleared generation in the first nine months of 2025 increased by 3.3 percent from the first nine months of 2024, from 96,954 MWh to 100,136 MWh.
- The day-ahead hourly average cleared supply in the first nine months of 2025, including INCs and UTCs, increased by 1.9 percent from the first nine months of 2024 from 112,192 MWh to 114,328 MWh.
- **Demand.** The real-time hourly peak load without exports in the first nine months of 2025 was 156,256 MWh (158,789 MWh with net exports) in the HE 1800 (EPT) on June 23, 2025, higher than the PJM peak load in the first nine months of 2024, which was 144,245 MWh (149,398 MWh with net exports) in the HE 1800 (EPT) on June 21, 2024.
- The real-time hourly average load in the first nine months of 2025 increased by 3.0 percent from the first nine months of 2024, from 90,917 MWh to 93,683 MWh.
- The day-ahead hourly average cleared demand in the first nine months of 2025, including DECs and UTCs, increased by 1.4 percent from the first nine months of 2024, from 106,355 MWh to 107,864 MWh.

Market Behavior

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 4.6 percent and the cleared increment MW increased by 8.4 percent in the first nine months of 2025 compared to the first nine months of 2024. The hourly average submitted decrement bid MW increased by 17.7 percent and the cleared decrement MW decreased by 2.6 percent in the first nine months of 2025 compared to the first nine months of 2024. The hourly average submitted up to congestion bid MW decreased by 2.1 percent and the cleared up to congestion bid MW decreased by 8.2 percent in the first nine months of 2025 compared to the first nine months of 2024.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2025, generation from coal units increased 16.1 percent, generation from natural gas units decreased 1.6 percent, generation from oil units increased 25.8 percent, generation from wind units increased 1.8 percent, and generation from solar units increased 46.4 percent compared to the first nine months of 2024.
- **Fuel Diversity.** The fuel diversity of energy generation in the first nine months of 2025, measured by the fuel diversity index for energy (FDI_e), increased 2.5 percent compared to the first nine months of 2024.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first nine months of 2025, coal units were 7.6 percent, natural gas units were 77.9 percent and wind units were 10.3 percent of marginal resources. In the first nine months of 2024, coal units were 11.0 percent, natural gas units were 74.8 and wind units were 11.9 percent of marginal resources.
- **Prices.** The real-time load-weighted average LMP in the first nine months of 2025 increased $16.20 per MWh, or 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh.

- The day-ahead load-weighted average LMP for the first nine months of 2025 increased $16.03 or 47.4 percent from the first nine months of 2024, from $33.85 per MWh to $49.88 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was $50.51 per MWh for the first nine months of 2025, which is 9.0 percent, $4.17 per MWh, higher than the real-time load-weighted average DLMP of $46.34 per MWh.
- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in the first nine months of 2025, 7.2 percent of the real-time load-weighted LMP was the result of coal costs, 43.4 percent was the result of gas costs, 4.3 percent was the result of the cost of emission allowances, and 10.5 percent was the result of transmission constraint violation penalty factors.
- **Components of Day-Ahead LMP.** In the PJM Day-Ahead Energy Market in the six months between April and September of 2025, 7.2 percent of the day-ahead load-weighted LMP was the result of coal costs, 12.2 percent was the result of gas costs, 33.2 percent was the result of the decrement bids, and 18.5 percent was the result of increment offers.
- **Changes in Real-Time LMP.** Of the $16.20 per MWh increase in the real-time load-weighted average LMP, $9.85 per MWh (60.8 percent) was the fuel and consumables cost components of LMP, -$0.16 per MWh (-1.0 percent) was the emissions cost components of LMP, $0.85 per MWh (5.2 percent) was the sum of the markup, maintenance, and ten percent adder components of LMP, $2.07 per MWh (12.8 percent) was the transmission constraint penalty factor component of LMP, and $1.14 per MWh (7.0 percent) was the scarcity component of LMP. The pre-emergency demand response called on by PJM during the hot weather days in June and July increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.11 per MWh, a 0.7 percent decrease.
- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The average difference between day-ahead and real-time average prices was $0.38 per MWh in the first nine months of 2025, and $0.41 per MWh in the first nine months of 2024. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- **Shortage Intervals.** There were 130 intervals with five minute shortage pricing on 22 days in the first nine months of 2025. Of the 130 intervals, 79 occurred during the June 2025 heatwave, for which PJM issued several emergency warnings and actions. Seven of the 130 intervals of shortage overlapped with synchronized reserve events.
- **SCED Shortage Intervals.** In the first nine months of 2025, there were 4,082 five minute intervals, or 5.2 percent of all five minute intervals, for which at least one RT SCED solution showed a shortage of reserves. In the first nine months of 2025, there were 1,368 five minute intervals, or 1.7 percent of all five minute intervals, for which more than one RT SCED solution showed a shortage of reserves. In the first nine months of 2025, PJM triggered shortage pricing for 130 five minute intervals, or 0.2 percent of all five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Three suppliers were jointly pivotal in the day-ahead market on 257 days, 94.1 percent of the days, in the first nine months of 2025 and 138 days, 50.4 percent of the days, in the first nine months of 2024.
- **Local Market Power.** In the first nine months of 2025, in the real-time market, the 500 kV system, 13 zones, and the PJM/MISO interface experienced congestion resulting from one or more constraints binding

for 75 or more hours. For seven out of the top 10 congested facilities (by real-time binding hours) in the first nine months of 2025, the average number of suppliers providing constraint relief was three or fewer. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 2.0 percent in the first nine months of 2024 to 1.9 percent in the first nine months of 2025. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.5 percent in the first nine months of 2024 to 1.4 percent in the first nine months of 2025. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.

  The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.18 percent in the first nine months of 2024 to 0.10 percent in the first nine months of 2025. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.23 percent in the first nine months of 2024 to 0.12 percent in the first nine months of 2025. The low offer cap percentages for reliability commitments, relative to offer capping for transmission constraints, do not mean that units committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated consistent with that fact.

- **Parameter Mitigation.** PJM applies operating parameter limits (PLS) to units that fail the TPS test and to all units during hot and cold weather alerts. In the first nine months of 2025, 29.3 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. On days when cold weather alerts and hot weather alerts were declared, 31.2 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first nine months of 2025, no units qualified for an FMU adder. In 2024, 2023 and 2022, no units qualified for an FMU adder. In 2021, one unit qualified for an FMU adder.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -$0.07 when using unadjusted cost-based offers in the first nine months of 2025, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first nine months of 2025 was more than $900 per MWh and the highest markup in the first nine months of 2024 was more than $900 per MWh, using unadjusted cost-based offers.

- While the average markup index in the day-ahead market was $0.23 per MWh in the six months between April and September of 2025, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the six months between April and September of 2025 was more than $550 per MWh.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup frequency distributions also show that a significant proportion of units were offered with high markups, consistent with the exercise of market power.

Market Performance

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

  In the PJM Real-Time Energy Market in the first nine months of 2025, the unadjusted markup component (net of positive and negative markup components) of LMP was -$0.09 per MWh or -0.2 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $2.74 per MWh, or 3.5 percent of the real-time peak hour load-weighted average LMP for July.

  In the PJM Day-Ahead Energy Market in the six months between April and September of 2025, the unadjusted markup component (net of positive and negative markup components) of LMP was $2.64 per MWh or 12.2 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $7.59 per MWh, or 8.59 percent of the day-ahead peak hour load-weighted average LMP for July.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 3.0 percent of all real-time marginal unit intervals in the first nine months of 2025, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.

- **Markup and Aggregate Market Power.** In the first nine months of 2025, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $100 per MWh on 117 days, compared to 76 days in the first nine months of 2024.[7] Some of the marginal units had local market power, but were not offer capped due to issues with the method that PJM uses to select offer schedules for units that fail the TPS test. Some of the marginal units had aggregate market power, for which there is no offer capping, and some had both local and aggregate market power.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers per the PJM Operating Agreement not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short

7 The number of days reported in the 2025 Quarterly State of the Market Report for PJM: January through March and the 2025 Quarterly State of the Market Report for PJM: January through June were understated, and have been correctly calculated in this 2025 Quarterly State of the Market Report for PJM: January through September.

run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Partially adopted 2023.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Partially adopted.)
- The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)[8]
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior

8 The real-time market formula for determining the lowest cost schedule is documented. The day-ahead market formula for determining the lowest cost schedule is not documented.

time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, that PJM commit all resources that fail the TPS test on their cost-based offers, that the Market Seller designate the cost-based offer if there is more than one, and that PJM implement this solution as soon as possible. (Priority: High. First reported Q3 2024. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)[9]

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage resources be subject to an enforceable ICAP must offer rule in the day-ahead and real-time energy markets that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, that gas generators be required to inform PJM about whether they have gas, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported 2022. Status: Not adopted.)

9 The applicability of the FMU and AU adders is limited by the rule implemented in 2014 requiring that net revenues must fall below avoidable costs, but the possibility of FMU and AU adders is still part of the PJM Market Rules.

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[10]
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported 2022. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[11]
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)

10 Flexible parameter standards are in place for combined cycle and combustion turbine resources when operating on a parameter limited schedule, but not for other schedules or generating technologies.

11 PJM created a more transparent process for transmission constraint penalty factors and added it to the tariff in 2020. Policies on reductions in control limits and the duration of violations remain discretionary and undocumented in the PJM Market Rules.

- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.[12] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[13] [14] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and LPC and instead limit the sum of violated reserve constraint shadow prices that are included in the determination of LMP in LPC to $1,700 per MWh. While PJM no longer caps prices in RT SCED, PJM continues to apply a cap to the system marginal price in the pricing run (LPC) under fast start pricing. (Priority: Medium. First reported 2021. Status: Not adopted.)

12 This recommendation was the result of load shed events in September, 2013. For detailed discussion, please see *2013 Annual State of the Market Report for PJM*, Volume 2: Section 3 at 114 – 116.

13 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

14 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. First reported 2021. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[15]
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[16]

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

15 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.
16 The PJM Market Rules clarify that shortage case approval will be based on RT SCED, but does not address RT SCED case choice or load bias.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2025, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market. In a competitive market, prices are directly related to input prices, the marginal cost to serve load. In the first nine months of 2025, LMP increased by $16.20 per MWh compared to the first nine months of 2024. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased $9.85 per MWh, 60.8 percent of the increase in LMP. The emissions cost components of LMP, including opportunity costs for emissions limited resources, decreased by $0.16 per MWh, -1.0 percent of the increase in LMP. The transmission constraint penalty factor component increased by $2.07 per MWh, 12.8 percent of the increase in LMP, primarily as a result of PJM actions to reduce the line limits applied in SCED (control limits) below the actual line limits. The pre-emergency demand response called on by PJM during the hot weather days in June and July increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.11 per MWh, a 0.7 percent decrease.

The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first nine months of 2025 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first nine months of 2025, the sum of the markup, ten percent adder, and maintenance cost (not short run marginal cost) components increased by $0.85 per MWh or 5.2 percent of the increase in LMP. In addition, PJM actions in the form of transmission constraint penalty factors, significantly increased prices.

The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to be addressed.[17] There also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels. For example, PJM approved 21.9 percent of solved shortage cases in June 2025, but only 3.2 percent for the first nine months of 2025. Six of the other eight months had a higher percent of shortage cases solved, but fewer approved. The pattern of shortage case approvals indicates that PJM considers factors that are not documented in the tariff when deciding whether to approve shortage cases. The application of shortage pricing should not involve operator discretion. As directed by FERC Order No. 825, PJM should approve shortage cases based on market software results alone.[18]

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised and to ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing for revenue adequacy, as in PJM's 2019 ORDC proposal that would have created administrative scarcity pricing, is not consistent with a competitive market design. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is consistent with a competitive market design. Scarcity pricing is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, that scarcity pricing not be excessive or punitive, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

PJM defined inputs to the dispatch tools, particularly RT SCED, have substantial effects on energy market outcomes. Transmission line ratings in SCED, transmission constraint penalty factors, load forecast bias, hydro resource schedules, fast start pricing, and the treatment of demand resources change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission constraint penalty factors. PJM operator interventions to reduce the control limits on transmission constraint line ratings in RT SCED unnecessarily trigger transmission constraint penalty factors and significantly increase prices. In the first nine months of 2025, the control limit used in RT SCED for 85 percent of violated transmission constraint intervals was less than 100 percent of the actual line limit, with an average reduction of 5.1 percent. If the control limits had not been artificially reduced for PJM transmission constraints and everything else remained unchanged, the transmission constraint penalty factor's contribution to the load weighted average LMP in the first nine months of 2025 would have decreased by 99.4 percent from $5.31 to $0.03 per MWh. PJM should evaluate its interventions in the market, including the unnecessary imposition of transmission constraint penalty factors, reconsider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and despite the stated goal of reducing overall uplift, created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[19] The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. Units that start in one hour are not actually fast start units, and their commitment

17 177 FERC ¶ 61,209 (2021).
18 155 FERC ¶ 61,276 at P 161 (2016) ("shortage pricing is required only when a shortage of energy or operating reserves is indicated by the RTO's/ISO's software").
19 See 173 FERC ¶ 61,244 (2020).

costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying uplift in an attempt to counter the distorted incentives inherent in fast start pricing. PJM is also using the pricing run to implement administrative pricing rules that are not related to fast start pricing. Specifically, PJM uses lower transmission constraint penalty factors in the day-ahead pricing run than in the dispatch run and implements system marginal price capping in the pricing run. Every difference between the dispatch run and the pricing run introduces another inefficiency in the market. In the four years since fast start pricing was introduced, the market has not responded with new entry of fast start units despite consistently higher LMPs when a fast start unit sets price.

The energy market requires more flexible operation of the dispatchable fleet as wind and solar resource penetration grows. Since 2018, PJM has argued that the way to incent investment in flexible units is to increase reserve requirements and to increase the administrative prices defined in the ORDCs. In fact, PJM's ORDCs would benefit inflexible units. Providing windfall gains to all generation through higher LMPs during more frequent reserve shortages is not an effective incentive for flexibility.

The question of how to provide market incentives for investment in flexibility, and for operating to the full capability of that flexibility should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? Are units inflexible because the PJM software does not model combined cycle transitions?

A direct solution would include improved modelling of generator capabilities, so that PJM can send more targeted dispatch signals that generators are consistently capable of following. A direct solution would include targeted reforms to PJM software, like multi-interval dispatch and combined cycle modelling would directly address PJM energy market performance. A direct solution would include stronger standards in the PJM Market Rules for performance of resources to their actual physical parameters. These reforms would be more efficient and effective than simply raising prices across the board.

The relationship between supply and demand is referred to as the supply-demand fundamentals, or economic fundamentals, or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes at all times. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market with increasing frequency. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[20] However, there are issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021, but failed to address them in its November 30, 2023 order.[21] [22] Many of these issues can be resolved by simple rule changes. PJM filed and, on October 25, 2024, FERC accepted a proposal that would require that sellers that fail the TPS test will be

20 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
21 See 175 FERC ¶ 61,231 (2021).
22 185 FERC ¶ 61,158 (2023).

offer capped at their cost-based offers and that operating parameters will be mitigated.[23] That order has no current effect because FERC approved the PJM filing that linked, for no logical reason, implementing the improved rules to PJM's adoption of an improved combined cycle model with no defined date. The flawed rules remain in place. There is no reason to delay implementation of the FERC approved rules until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The approved approach should be implemented as soon as possible to help ensure effective market power mitigation.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs in cost-based energy offers that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs. This rule also had unintended consequences for market seller offer caps in the capacity market. Maintenance costs includable in energy offers cannot be included in capacity market offer caps based on avoidable costs. As a result, capacity market offer caps based on net avoidable costs were lower than they would have been if maintenance costs had been correctly included in avoidable costs rather than incorrectly defined to be part of short marginal costs of producing energy and includable in energy offers.

A competitive power market will result in higher prices when fuel costs increase and lower prices when fuel costs decrease. A competitive market will not result in higher prices when markups increase based on market power, or when PJM selects a price-based offer including a markup rather than a cost-based offer in the presence of local market power, or when PJM artificially triggers transmission constraint penalty factors. The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in the first nine months of 2025 or prior years. Given the structure of the energy market which can permit the exercise of aggregate and local market power, some participants' offer behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. In addition, PJM's extensive administrative interventions in the energy market should be reduced. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2025.

23 189 FERC ¶ 61,060 (2024).

Supply and Demand

Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2025, 2,756 MW of new resources were added in the energy market, and 982 MW of resources were retired.

Figure 3-1 shows real-time and day-ahead hourly supply curves for the first nine months of 2024 and 2025.[24] The real-time supply curve includes hourly on peak average offers. The real-time supply curve only includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows all available hourly on peak average offers.

The real-time hourly on peak average offered supply in the first nine months of 2025 increased by 1.4 percent, from the first nine months of 2024, from 140,934 MWh to 142,851 MWh. The day-ahead hourly average offered supply in the first nine months of 2025 decreased by 1.5 percent, from the first nine months of 2024, from 153,603 MWh to 151,275 MWh.

24 Real-time supply includes real-time generation offers and import MWh.

Figure 3-1 Real-time and day-ahead hourly supply curves: January through September, 2024 and 2025

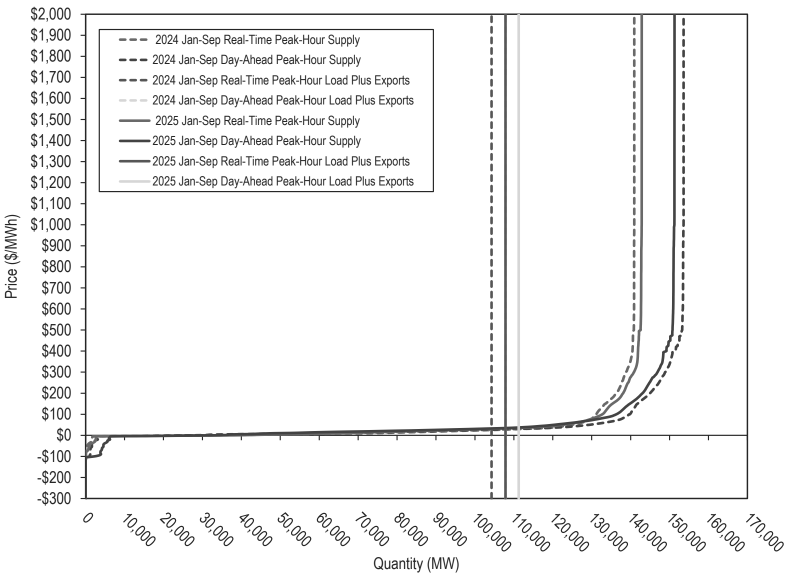


Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

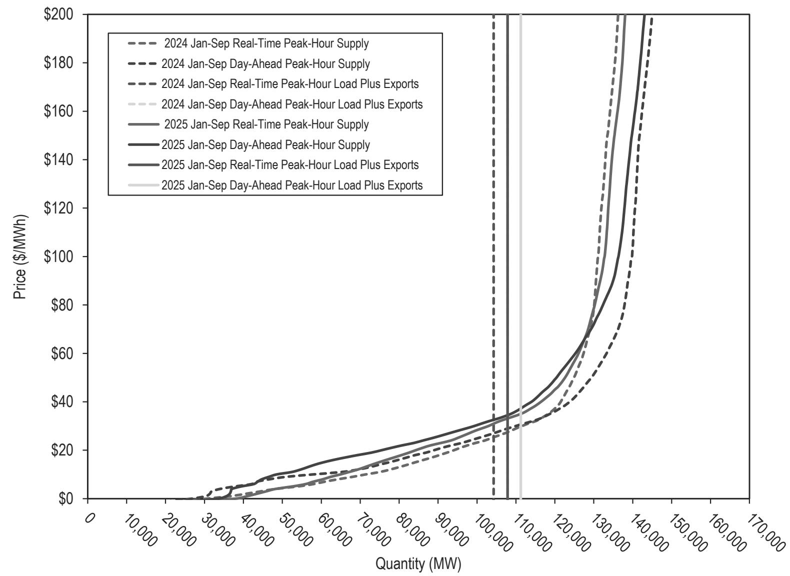


Table 3-2 shows the price elasticity of the real-time supply curve for the peak hours for the first nine months of 2024 and 2025 by load level.[25]

The supply curve in the first nine months of 2025 was most elastic in the 95 to 115 GW range at 0.428, which was more elastic than the supply curve in the 95 to 115 GW range in the first nine months of 2024, with an elasticity of 0.378.

The price elasticity of the supply curve measures the responsiveness of the quantity supplied (GW) to a change in price:

$$\text{Elasticity of Supply} = \frac{\text{Percent change in quantity supplied}}{\text{Percent change in price}}$$

25 The price elasticity results have been corrected from previous reports.

The supply curve is defined to be elastic when elasticity is greater than 1.0. The quantity supplied is more sensitive to changes in price the higher the elasticity. Although the aggregate supply curve may appear flat as a result of the wide range in prices and quantities, the supply curve is inelastic throughout.

Table 3-2 Price elasticity of the supply curve

	GW				
Jan-Sep	Min - 75	75 - 95	95 - 115	115 - 135	135 - Max
2020	0.138	0.643	0.686	0.039	0.004
2021	0.089	0.657	0.502	0.050	0.007
2022	0.046	0.556	0.384	0.102	0.012
2023	0.096	0.361	0.428	0.020	0.005
2024	0.108	0.316	0.378	0.032	0.008
2025	0.061	0.428	0.387	0.053	0.009

Real-Time Supply

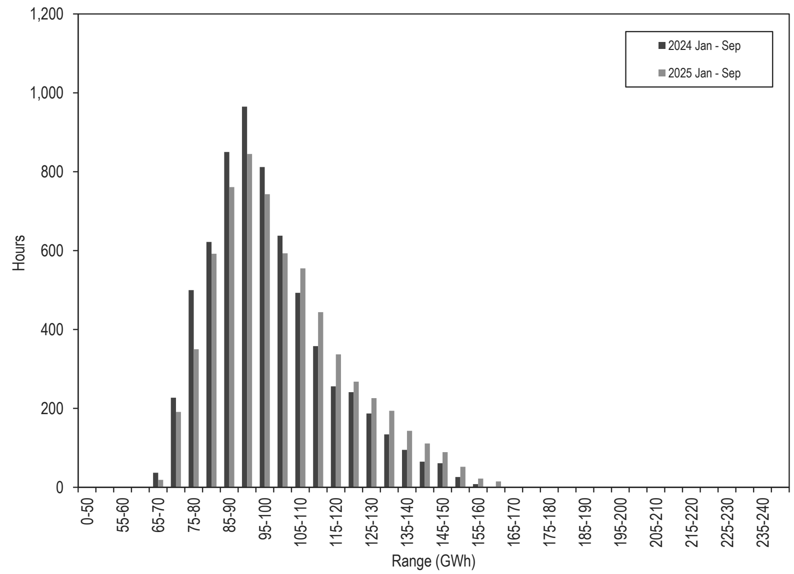
In the PJM Real-Time Energy Market, there are three types of supply offers:[26]

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the fixed MW.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-3 shows the hourly distribution of the real-time generation plus imports for the first nine months of 2024 and 2025.

Figure 3-3 Distribution of real-time generation plus imports: January through September, 2024 and 2025[27]



PJM Real-Time Average Cleared Supply

Table 3-3 shows the real-time hourly average cleared supply and its standard deviation for the first nine months of 2001 through 2025.

The real-time hourly average cleared generation in the first nine months of 2025 increased by 3.3 percent from the first nine months of 2024, from 96,954 MWh to 100,136 MWh.

26 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

27 Each range on the horizontal axis excludes the start value and includes the end value.

The real-time hourly average cleared supply including imports in the first nine months of 2025 increased by 3.5 percent from the first nine months of 2024, from 98,593 MWh to 102,018 MWh.

The real-time hour average cleared generation in the first nine months of 2025 was the highest since the start of PJM markets for the first nine months of a year at 100,136 MWh.

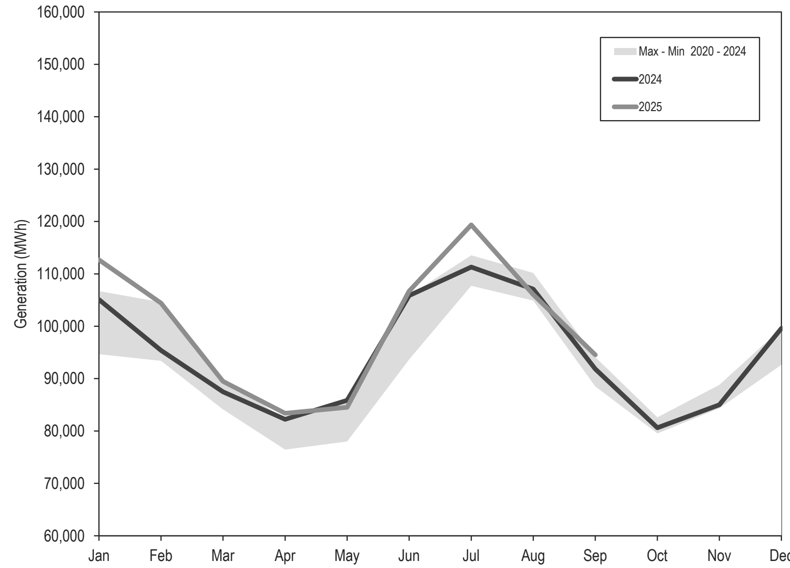
Table 3-3 Real-time hourly average generation and generation plus imports: January through September, 2001 through 2025

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Sep	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	30,304	5,216	33,299	5,571	NA	NA	NA	NA
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%
2015	91,901	16,711	97,896	17,863	(0.6%)	4.4%	(0.0%)	4.7%
2016	92,799	19,003	96,907	19,067	1.0%	13.7%	(1.0%)	6.7%
2017	91,658	15,964	93,639	16,216	(1.2%)	(16.0%)	(3.4%)	(15.0%)
2018	95,561	17,506	97,588	17,747	4.3%	9.7%	4.2%	9.4%
2019	95,531	17,206	96,659	17,378	(0.0%)	(1.7%)	(1.0%)	(2.1%)
2020	92,226	17,790	92,983	17,883	(3.5%)	3.4%	(3.8%)	2.9%
2021	95,792	18,039	96,519	18,173	3.9%	1.4%	3.8%	1.6%
2022	96,397	16,816	98,064	17,031	0.6%	(6.8%)	1.6%	(6.3%)
2023	93,886	15,544	95,437	15,561	(2.6%)	(7.6%)	(2.7%)	(8.6%)
2024	96,954	16,635	98,593	16,917	3.3%	7.0%	3.3%	8.7%
2025	100,136	18,290	102,018	18,551	3.3%	10.0%	3.5%	9.7%

PJM Real-Time Monthly Average Cleared Supply

Figure 3-4 compares the real-time monthly average generation in 2024 and the first nine months of 2025 with the historic five year range. The real-time monthly average generation in January, April, June, and September 2025 was higher than the maximum monthly average generation for the past five years.

Figure 3-4 Real-time monthly average generation: 2024 through September 2025



Day-Ahead Supply

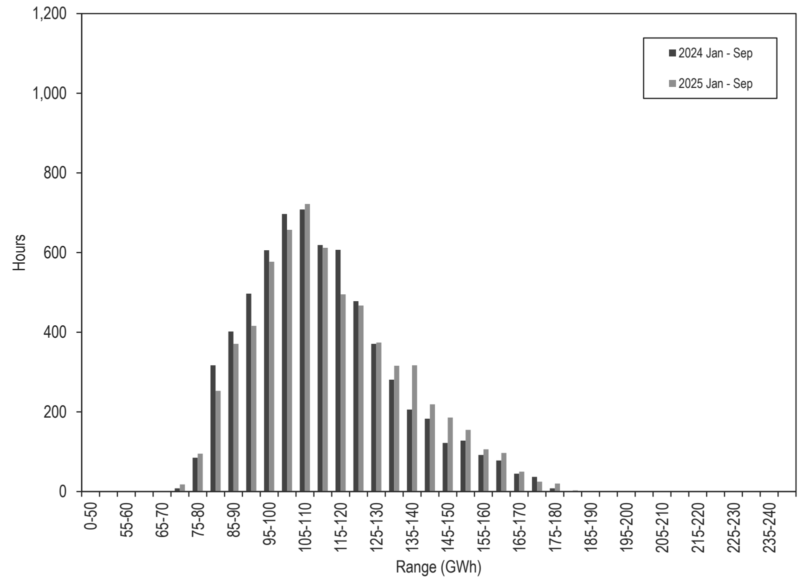
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the day-ahead energy market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the day-ahead energy market will not physically flow in real-time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-5 shows the distribution of the day-ahead hourly cleared supply, including increment offers, up to congestion transactions, and imports for the first nine months of 2024 and 2025.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through September, 2024 and 2025[28]



PJM Day-Ahead Average Cleared Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for each year for the first nine months of 2001 through 2025.

The day-ahead hourly average cleared supply in the first nine months of 2025, including INCs and UTCs, increased by 1.9 percent from the first nine months of 2024 from 112,192 MWh to 114,328 MWh.

28 Each range on the horizontal axis excludes the start value and includes the end value.

The day-ahead hourly average cleared supply in the first nine months of 2025, including INCs, UTCs and imports, increased by 1.9 percent from the first nine months of 2024, from 112,477 MWh to 114,585 MWh.

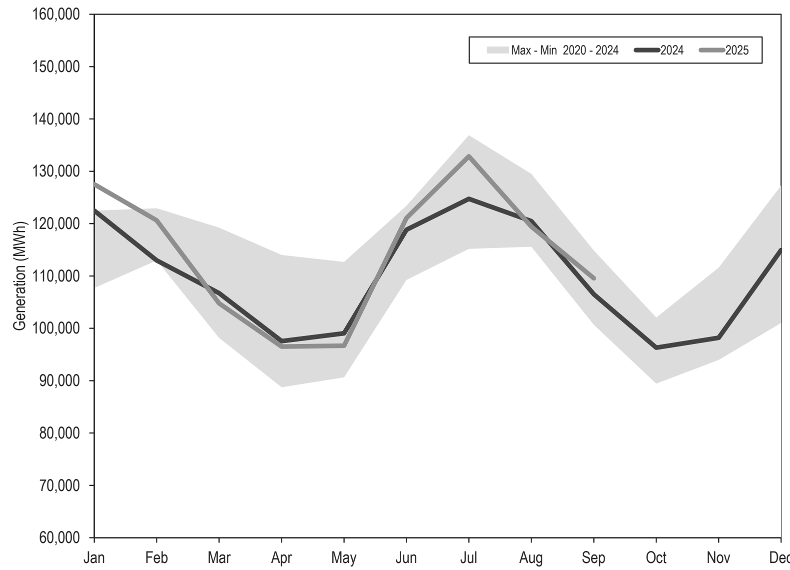
Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: January through September, 2001 through 2025

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Sep	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	27,519	4,839	28,279	4,911	NA	NA	NA	NA
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%
2015	116,975	20,289	119,349	20,502	(27.4%)	(15.2%)	(27.0%)	(14.9%)
2016	133,089	23,414	134,881	23,403	13.8%	15.4%	13.0%	14.1%
2017	133,377	20,602	134,000	20,710	0.2%	(12.0%)	(0.7%)	(11.5%)
2018	116,068	21,950	116,471	21,939	(13.0%)	6.5%	(13.1%)	5.9%
2019	118,913	20,009	119,249	19,989	2.5%	(8.8%)	2.4%	(8.9%)
2020	115,205	20,611	115,386	20,577	(3.1%)	3.0%	(3.2%)	2.9%
2021	104,785	20,136	104,970	20,154	(9.0%)	(2.3%)	(9.0%)	(2.1%)
2022	110,598	19,369	110,875	19,455	5.5%	(3.8%)	5.6%	(3.5%)
2023	119,823	18,378	120,158	18,427	8.3%	(5.1%)	8.4%	(5.3%)
2024	112,192	19,975	112,477	20,061	(6.4%)	8.7%	(6.4%)	8.9%
2025	114,328	20,898	114,585	20,951	1.9%	4.6%	1.9%	4.4%

PJM Day-Ahead Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead monthly average cleared supply including increment offers and up to congestion transactions in 2024 and the first nine months of 2025 with the historic five year range. The monthly average day-ahead cleared supply from January of 2025 was higher than the maximum of the past five years.

Figure 3-6 Day-ahead monthly average cleared supply: 2024 through September 2025



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply in the first nine months of 2024 and 2025. The last two columns of Table 3-5 are the day-ahead cleared supply minus the real-time cleared supply. The first column is the total physical day-ahead generation less the total physical real-time generation and the second column is the total day-ahead cleared supply less the total real-time cleared supply. The total real-time cleared supply includes real-time generation and real-time imports. The total day-ahead cleared supply includes physical day-ahead generation, INCs, UTCs, and day-ahead imports.

The total physical day-ahead average generation less the total physical real-time average generation in the first nine months of 2025 decreased 346 MWh from the first nine months of 2024, from -653 MWh to -999 MWh. The total day-ahead average supply less the total real-time average supply in the first nine months of 2025 decreased 1,316 MWh from the first nine months of 2024, from 13,883 MWh to 12,567 MWh.

Table 3-5 Day-ahead and real-time hourly cleared supply (MWh): January through September, 2024 and 2025

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Jan-Sep	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2024	96,301	4,886	11,005	285	112,477	96,954	98,593	(653)	13,883
	2025	99,137	5,297	9,894	257	114,585	100,136	102,018	(999)	12,567
Median	2024	92,652	4,788	10,785	250	109,722	93,930	95,474	(1,278)	14,248
	2025	95,452	5,234	9,596	198	111,246	96,704	98,361	(1,252)	12,885
Standard Deviation	2024	17,823	1,681	4,394	249	20,061	16,635	16,917	1,189	3,144
	2025	18,693	1,734	3,504	228	20,951	18,290	18,551	403	2,400
Peak Average	2024	104,395	5,617	12,903	358	123,273	104,367	106,270	29	17,003
	2025	107,319	6,106	11,340	310	125,075	107,890	109,926	(572)	15,150
Peak Median	2024	100,381	5,529	12,650	315	119,613	100,820	102,576	(439)	17,038
	2025	104,073	5,960	11,074	259	121,688	104,759	106,529	(686)	15,160
Peak Standard Deviation	2024	17,202	1,588	4,054	291	17,580	16,090	16,364	1,112	1,216
	2025	18,208	1,592	3,215	250	18,980	17,948	18,166	260	814
Off-Peak Average	2024	89,202	4,245	9,341	221	103,009	90,453	91,861	(1,251)	11,148
	2025	91,983	4,590	8,629	211	105,413	93,356	95,104	(1,373)	10,309
Off-Peak Median	2024	86,704	4,157	8,727	200	99,777	88,183	89,466	(1,479)	10,311
	2025	88,979	4,500	8,280	155	102,154	90,331	91,908	(1,353)	10,246
Off-Peak Standard Deviation	2024	15,132	1,488	3,988	183	17,103	14,211	14,330	921	2,773
	2025	15,982	1,532	3,248	195	18,097	15,712	15,940	270	2,157

Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day for the first nine months of 2025. The day-ahead cleared supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time cleared supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time cleared supply (Average volumes by hour of the day): January through September, 2025

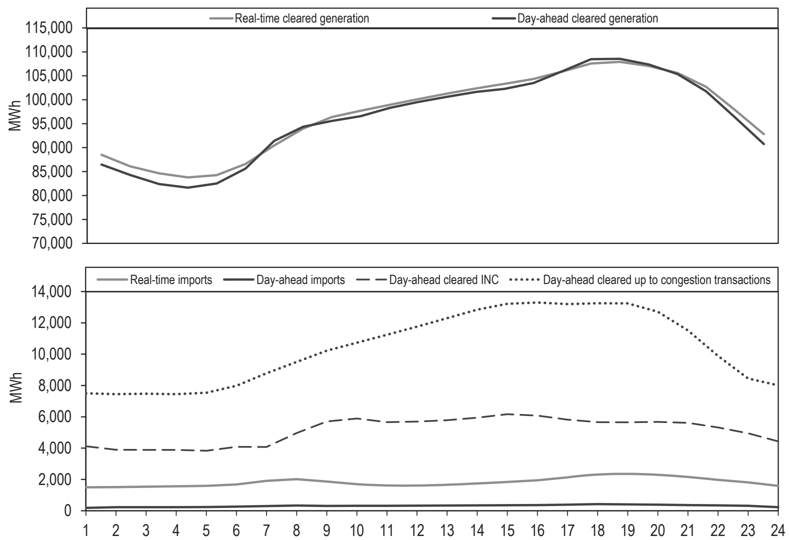
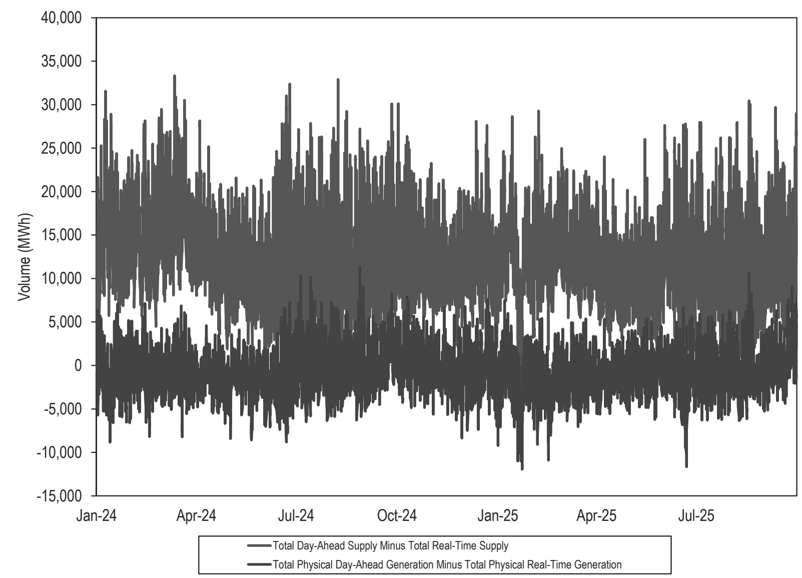


Figure 3-8 shows the difference between day-ahead and real-time daily average cleared supply in 2024 and the first nine months of 2025. The blue line is the total physical day-ahead generation less the total physical real-time generation, and the green line is the total day-ahead cleared supply less the total real-time cleared supply. The total real-time cleared supply includes real-time generation and real-time imports. The total day-ahead cleared supply includes physical day-ahead generation, INCs, UTCs, and day-ahead imports.

Figure 3-8 Difference between day-ahead and real-time daily average cleared supply: 2024 through September 2025



Demand

In the real-time energy market, demand includes physical load and exports. In the day-ahead energy market, demand includes physical load, exports, and virtual transactions.

Peak Demand

In the real-time energy market, demand refers to physical accounting load and exports, and in the day-ahead energy market, demand also includes virtual demand transactions.[29]

29 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

Table 3-6 shows the seasonal peak load, net exports, real-time generation and the LMP for the peak load hour from 2004 through September 2025.

The winter peak load in 2025 was 140,043 MWh in the HE 0900 (EPT) on January 22, 2025, higher than the winter peak load in 2024, which was 130,293 MWh in the HE 0900 (EPT) on January 17, 2024. This was the highest winter peak load since the start of the PJM market.

The summer peak load in the first nine months of 2025 was 156,256 MWh in the HE 1800 (EPT) on June 23, 2025, higher than the summer peak load in 2024, which was 144,245 MWh in the HE 1800 (EPT) on June 21, 2024. This was the highest summer peak load since the start of the PJM market.

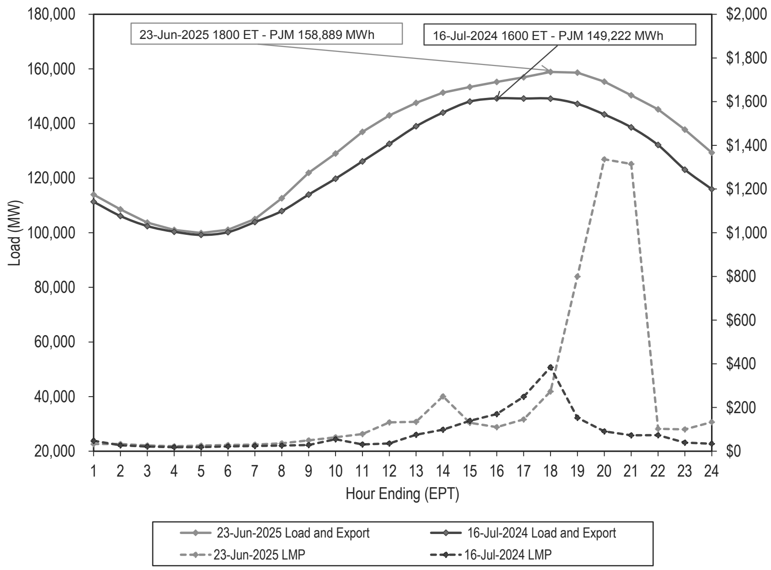
Table 3-6 Actual PJM peak load by season: 2004 through September 2025[30 31]

Summer Peak Load Hour						Winter Peak Load Hour					
Date	Hour Ending	RT Load (MWh)	Net Export (MWh)	RT Generation (MWh)	LMP ($/MWh)	Date	Hour Ending	RT Load (MWh)	Net Export (MWh)	RT Generation (MWh)	LMP ($/MWh)
Tuesday, August 03, 2004	17	77,950	435	78,666	$90.55	Monday, December 20, 2004	19	96,838	1,796	98,797	$129.90
Tuesday, July 26, 2005	16	134,017	(2,206)	131,975	$156.02	Wednesday, December 14, 2005	19	110,632	(376)	110,406	$163.45
Wednesday, August 02, 2006	17	144,904	(782)	143,957	$404.80	Friday, December 08, 2006	19	106,866	873	108,002	$83.17
Wednesday, August 08, 2007	16	136,368	404	140,170	$471.98	Monday, February 05, 2007	20	119,072	(3,964)	115,252	$178.18
Monday, June 09, 2008	17	127,216	2,862	125,804	$155.67	Thursday, January 03, 2008	19	109,239	(641)	112,339	$130.11
Monday, August 10, 2009	17	123,900	163	127,229	$85.64	Friday, January 16, 2009	19	114,765	(2,316)	115,093	$80.73
Tuesday, July 06, 2010	17	133,297	(247)	136,442	$194.02	Tuesday, December 14, 2010	19	113,121	(1,688)	115,284	$137.02
Thursday, July 21, 2011	17	154,095	(5,906)	151,790	$162.28	Monday, January 24, 2011	8	108,156	(1,218)	109,394	$176.49
Tuesday, July 17, 2012	17	150,879	(4,825)	149,582	$203.72	Tuesday, January 03, 2012	19	119,450	109	122,802	$67.07
Thursday, July 18, 2013	17	153,790	(7,607)	149,806	$244.92	Tuesday, January 22, 2013	19	123,473	(3,412)	123,283	$119.20
Tuesday, June 17, 2014	18	138,448	(7,382)	134,914	$113.51	Tuesday, January 07, 2014	19	136,932	(9,127)	131,731	$386.36
Tuesday, July 28, 2015	17	140,266	(3,942)	139,450	$101.40	Friday, February 20, 2015	8	139,647	(6,994)	137,504	$381.93
Thursday, August 11, 2016	16	148,577	1,235	153,820	$128.83	Thursday, December 15, 2016	19	127,759	(2,946)	128,979	$107.06
Wednesday, July 19, 2017	18	142,387	3,166	148,409	$59.49	Monday, January 09, 2017	8	124,210	(1,054)	126,761	$67.72
Tuesday, August 28, 2018	17	147,042	3,238	154,067	$131.36	Friday, January 05, 2018	19	133,851	(403)	137,173	$164.15
Friday, July 19, 2019	18	148,228	3,253	154,542	$37.47	Thursday, January 31, 2019	8	134,060	1,077	138,744	$85.21
Monday, July 20, 2020	17	141,449	6,013	150,667	$74.91	Wednesday, January 22, 2020	8	116,761	4,230	123,609	$31.76
Tuesday, August 24, 2021	17	145,563	2,984	151,708	$243.98	Friday, January 29, 2021	9	114,457	3,200	120,648	$27.87
Wednesday, July 20, 2022	18	144,356	3,190	151,620	$204.29	Friday, December 23, 2022	19	131,474	3,340	136,132	$2,011.80
Thursday, July 27, 2023	18	144,215	7,211	151,896	$110.52	Friday, February 03, 2023	20	117,705	746	121,952	$56.22
Tuesday, July 16, 2024	18	148,890	508	152,864	$384.56	Wednesday, January 17, 2024	9	130,293	9,291	143,324	$103.66
Monday, June 23, 2025	18	156,256	2,533	162,599	$273.39	Wednesday, January 22, 2025	9	140,043	7,660	151,437	$355.76

30 Peak loads shown are accounting load, without losses. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions," for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.
31 Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017.

Figure 3-9 compares prices and load plus net exports on the peak load days for the first nine months of 2024 and 2025. The real-time average LMP for July 16, 2024, peak load hour was $33.90 per MWh, and for June 23, 2025, peak load hour it was $273.39 per MWh.

Figure 3-9 Peak load and net export day comparison



Real-Time Demand

In the PJM Real-Time Energy Market, there are two types of demand:[32]

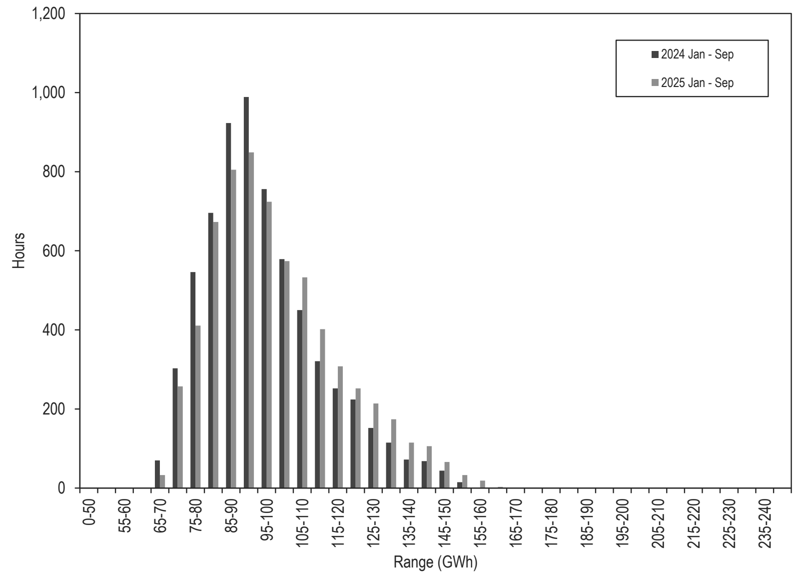
- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority's checkout process.

32 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of the real-time hourly load plus exports for the first nine months of 2024 and 2025.[33]

Figure 3-10 Distribution of real-time load plus exports: January through September, 2024 and 2025[34]



33 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

34 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time Average Demand

Table 3-7 presents real-time hourly demand summary statistics for the first nine months of 2001 through 2025.[35]

The real-time hourly average load in the first nine months of 2025 increased by 3.0 percent from the first nine months of 2024, from 90,917 MWh to 93,683 MWh.

The real-time hourly average demand including exports in the first nine months of 2025 increased by 3.5 percent from the first nine months of 2024, from 96,746 MWh to 100,114 MWh.

The real-time hourly average load in the first nine months of 2025 was the highest since the start of the PJM market for the first nine months of a year at 93,683 MWh.

Table 3-7 Real-time hourly average load and load plus exports: January through September, 2001 through 2025

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Sep	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,060	6,156	32,900	5,861	NA	NA	NA	NA
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%
2015	91,857	17,211	96,102	17,300	1.4%	3.3%	0.1%	4.7%
2016	90,599	18,183	95,340	18,571	(1.4%)	5.6%	(0.8%)	7.3%
2017	87,243	16,008	91,954	15,794	(3.7%)	(12.0%)	(3.6%)	(15.0%)
2018	91,905	17,064	95,795	17,245	5.3%	6.6%	4.2%	9.2%
2019	89,834	16,794	94,918	16,924	(2.3%)	(1.6%)	(0.9%)	(1.9%)
2020	85,886	17,201	91,356	17,464	(4.4%)	2.4%	(3.8%)	3.2%
2021	89,515	16,875	94,746	17,748	4.2%	(1.9%)	3.7%	1.6%
2022	90,514	16,367	96,196	16,581	1.1%	(3.0%)	1.5%	(6.6%)
2023	87,269	14,833	93,709	15,199	(3.6%)	(9.4%)	(2.6%)	(8.3%)
2024	90,917	16,529	96,746	16,478	4.2%	11.4%	3.2%	8.4%
2025	93,683	17,631	100,114	18,080	3.0%	6.7%	3.5%	9.7%

35 Accounting load is used because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the incorporation of marginal loss pricing in LMP.

PJM Real-Time Monthly Average Demand

Figure 3-11 compares the real-time monthly average load plus exports of 2024 and the first nine months of 2025 with the historic five year range. The real-time monthly average load plus exports in January, February, April, June and September 2025 was higher than the maximum monthly average load plus exports for the past five years.

Figure 3-11 Real-time monthly average hourly load plus exports: 2024 through September 2025

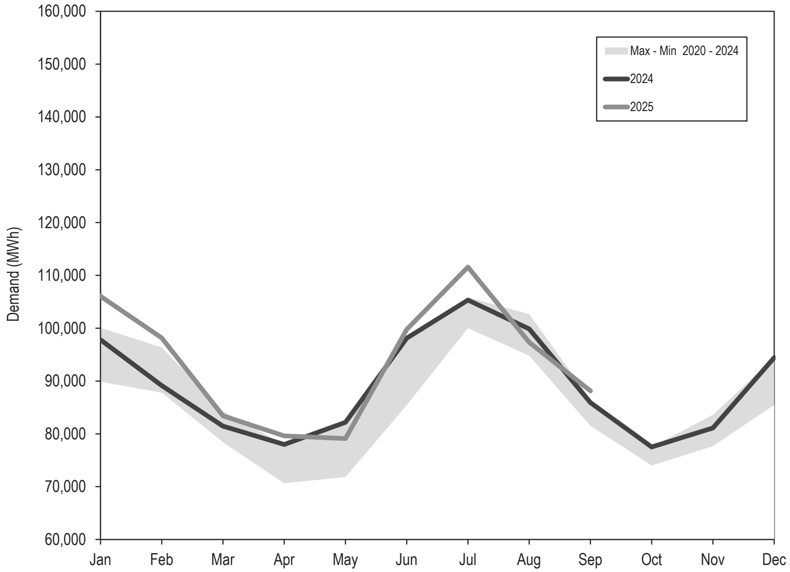
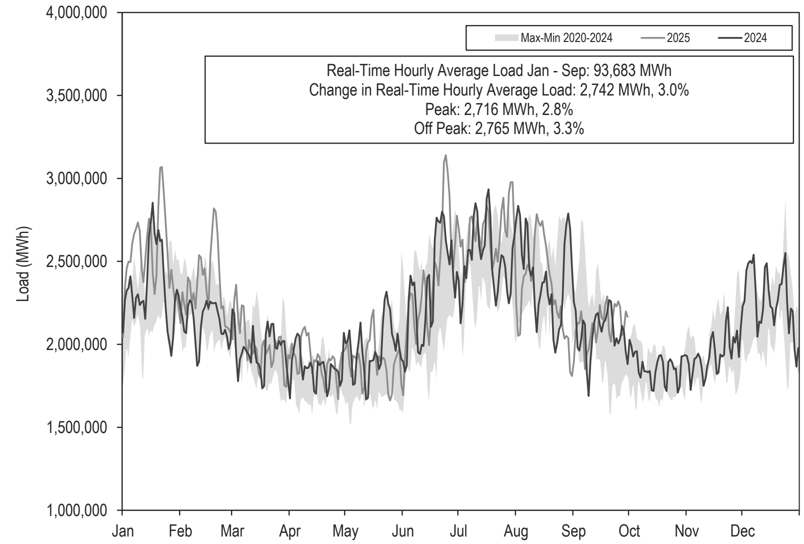


Figure 3-12 compares the real-time daily average load in 2024 and the first nine months of 2025, with the historic five year range. The daily average load in the first nine months of 2025 was higher than the historic five year range in January, February and June.

Figure 3-12 Real-time daily load: 2024 through September 2025



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and cooling degree days in 2024 and the first nine months of 2025.[36]

36 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). Reference: <https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php>. This calculation was modified starting in 2024 Q3 from the method used in prior State of the Market Reports which was the PJM calculation method based on 60 degrees for heating degree days and 65 degrees for cooling degree days.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Heating degree days increased 19.0 percent compared to the first nine months of 2024. Cooling degree days decreased 12.8 percent compared to the first nine months of 2024.

Table 3-8 Heating and cooling degree days: 2024 through September 2025

	2024		2025		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	799	0	985	0	23.3%	0.0%
Feb	562	0	720	0	28.1%	0.0%
Mar	381	0	370	2	(2.9%)	0.0%
Apr	157	18	173	10	10.1%	(43.6%)
May	9	98	21	31	137.3%	(68.8%)
Jun	0	326	1	302	0.0%	(7.4%)
Jul	0	408	0	433	0.0%	6.1%
Aug	0	326	0	242	0.0%	(25.9%)
Sep	0	152	0	139	0.0%	(9.0%)
Oct	94	11				
Nov	310	2				
Dec	699	0				
Jan-Sep	1,909	1,329	2,270	1,158	19.0%	(12.8%)

Day-Ahead Demand

In the PJM Day-Ahead Energy Market, there are five types of financially binding demand bids:

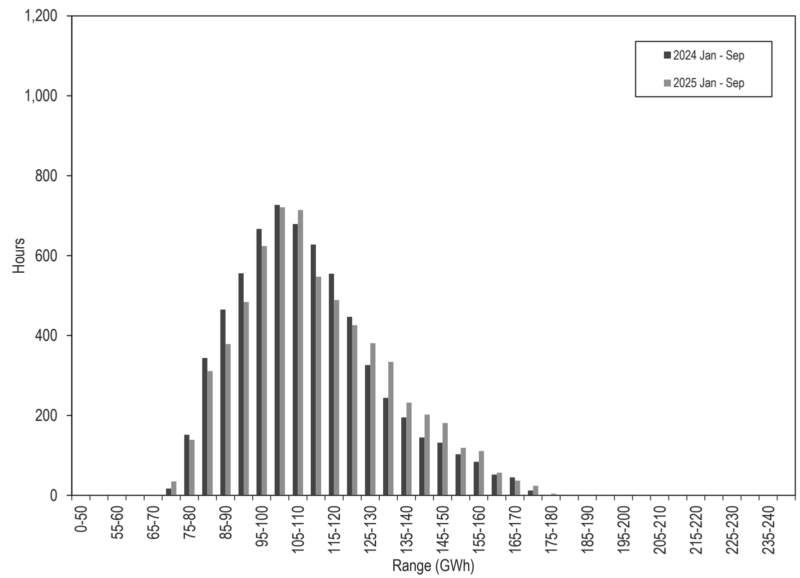
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the day-ahead energy market will not physically flow in real-time unless it is also submitted through the real-time energy market scheduling process.

PJM day-ahead demand is the sum of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-13 shows the hourly distribution of the day-ahead cleared demand including DECs, UTCs and exports for the first nine months of 2024 and 2025.

Figure 3-13 Distribution of day-ahead cleared demand plus exports: January through September, 2024 and 2025[37]



37 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead Average Demand

Table 3-9 shows day-ahead hourly average cleared demand including DECs, UTCs and exports for the first nine months of 2001 through 2025.

The day-ahead hourly average cleared demand in the first nine months of 2025, including DECs and UTCs, increased by 1.4 percent from the first nine months of 2024, from 106,355 MWh to 107,864 MWh.

The day-ahead hourly average cleared demand in the first nine months of 2025, including DECs, UTCs and exports, increased by 1.9 percent from the first nine months of 2024, from 110,189 MWh to 112,308 MWh.

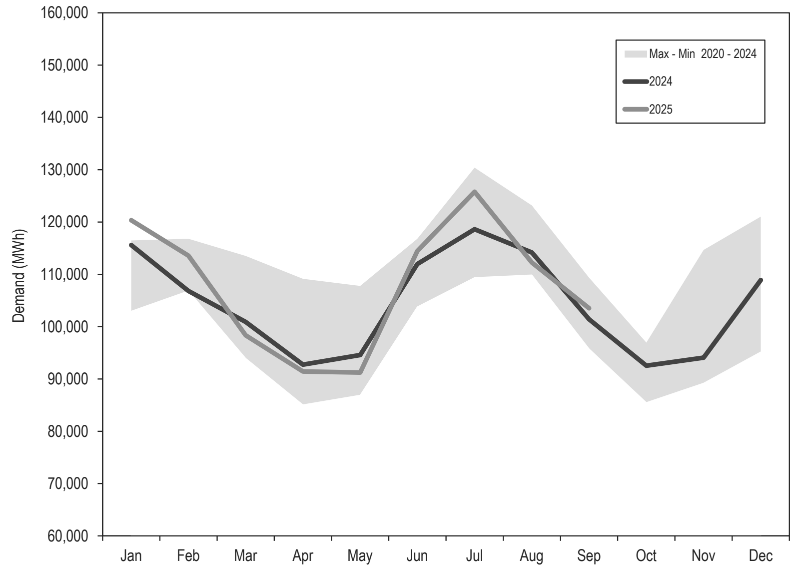
Table 3-9 Day-ahead hourly average cleared demand and demand plus exports: January through September, 2001 through 2025

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Sep	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,944	7,016	34,444	6,817	NA	NA	NA	NA
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.3%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(3.9%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.0%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,555	19,789	116,912	19,957	(27.5%)	(16.1%)	(27.1%)	(15.2%)
2016	129,048	22,492	132,405	22,801	13.6%	13.7%	13.3%	14.2%
2017	128,453	20,002	131,572	20,158	(0.5%)	(11.1%)	(0.6%)	(11.6%)
2018	111,589	21,194	114,373	21,392	(13.1%)	6.0%	(13.1%)	6.1%
2019	114,133	19,233	117,048	19,465	2.3%	(9.3%)	2.3%	(9.0%)
2020	109,850	19,762	113,188	20,089	(3.8%)	2.7%	(3.3%)	3.2%
2021	99,788	19,097	102,947	19,632	(9.2%)	(3.4%)	(9.0%)	(2.3%)
2022	105,195	18,664	108,685	18,945	5.4%	(2.3%)	5.6%	(3.5%)
2023	113,807	17,840	117,715	17,977	8.2%	(4.4%)	8.3%	(5.1%)
2024	106,355	19,453	110,189	19,559	(6.5%)	9.0%	(6.4%)	8.8%
2025	107,864	20,202	112,308	20,469	1.4%	3.9%	1.9%	4.7%

PJM Day-Ahead Monthly Average Demand

Figure 3-14 compares the day-ahead monthly average cleared demand including DECs and UTCs for 2024 and the first nine months of 2025, with the historic five year range. In January 2025, the day-ahead monthly average cleared demand was higher than the maximum of the past five years.

Figure 3-14 Day-ahead monthly average cleared demand: 2024 through September 2025



Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for day-ahead and real-time cleared demand for the first nine months of 2024 and 2025. The last two columns of Table 3-10 are day-ahead cleared demand minus real-time cleared demand. The first column is the total physical day-ahead load (fixed demand plus cleared price-sensitive demand) less the physical real-time load. The second column is the total cleared day-ahead demand less the total cleared real-time demand.

The total physical day-ahead average load less the total physical real-time average load in the first nine months of 2025 decreased 288 MWh from the first nine months of 2024, from -1,014 MWh to -1,302 MWh. The total day-ahead average demand less the total real-time average demand in the first nine months of 2025 decreased 1,249 MWh from the first nine months of 2024, from 13,443 MWh to 12,194 MWh.

Table 3-10 Day-ahead and real-time demand (MWh): January through September, 2024 and 2025

		Day Ahead						Real Time		Day Ahead Less Real Time	
Jan-Sep	Year	Fixed Demand	Price Sensitive	DEC Bids	Up to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2024	89,529	375	5,446	11,005	3,835	110,189	90,917	96,746	(1,014)	13,443
	2025	91,975	407	5,589	9,894	4,445	112,308	93,683	100,114	(1,302)	12,194
Median	2024	86,498	372	5,206	10,785	3,789	107,476	87,953	93,723	(1,084)	13,753
	2025	88,767	400	5,320	9,596	4,358	109,019	90,530	96,618	(1,363)	12,401
Standard Deviation	2024	16,317	61	1,827	4,394	1,056	19,559	16,529	16,478	(150)	3,081
	2025	17,083	86	2,004	3,504	1,137	20,469	17,631	18,080	(462)	2,389
Peak Average	2024	97,603	384	6,085	12,903	3,801	120,776	98,693	104,272	(707)	16,503
	2025	99,971	426	6,359	11,340	4,489	122,586	101,452	107,857	(1,055)	14,729
Peak Median	2024	94,039	381	5,943	12,650	3,760	117,273	94,661	100,704	(241)	16,569
	2025	96,890	422	6,209	11,074	4,344	119,258	98,093	104,605	(781)	14,653
Peak Standard Deviation	2024	15,270	58	1,743	4,054	1,073	17,124	15,721	15,919	(393)	1,205
	2025	16,219	86	1,955	3,215	1,214	18,543	16,963	17,691	(657)	852
Off-Peak Average	2024	82,449	367	4,885	9,341	3,864	100,906	84,098	90,146	(1,283)	10,760
	2025	84,982	390	4,915	8,629	4,406	103,322	86,890	93,344	(1,518)	9,978
Off-Peak Median	2024	79,906	357	4,588	8,727	3,811	97,795	81,656	87,876	(1,393)	9,919
	2025	82,065	379	4,603	8,280	4,367	100,091	83,805	90,319	(1,362)	9,772
Off-Peak Standard Deviation	2024	13,712	63	1,711	3,988	1,041	16,628	14,020	13,937	(245)	2,691
	2025	14,568	83	1,791	3,248	1,064	17,652	15,239	15,519	(588)	2,133

Figure 3-15 shows the average cleared volumes of day-ahead and real-time demand for the first nine months of 2025. The day-ahead demand includes day-ahead load, decrement bids, up to congestion transactions, and day-ahead exports. The real-time demand includes real-time load and real-time exports.

Figure 3-15 Day-ahead and real-time demand (Average hourly volumes): January through September, 2025

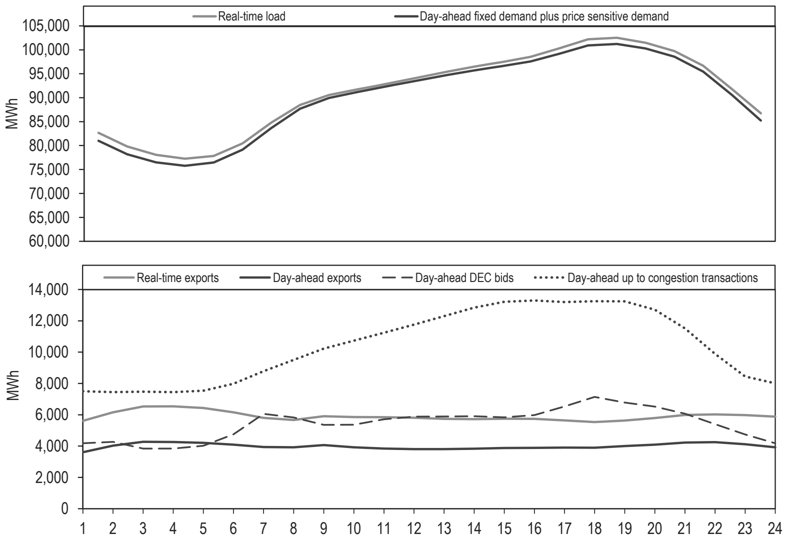


Figure 3-16 shows the difference between the physical day-ahead load and the physical real-time load, and the difference between the day-ahead demand including DECs, UTCs, and exports, and the real-time demand including exports, for 2024 and the first nine months of 2025.

Figure 3-16 Day-ahead minus real-time daily demand: 2024 through September 2025

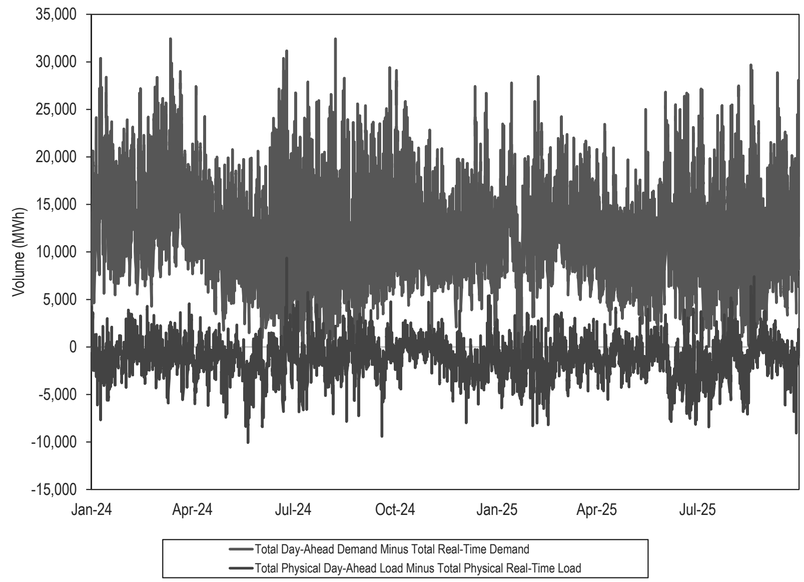


Figure 3-17 shows the difference between the day-ahead and real-time hourly average load by hour of the day. DECs, UTCs and exports are not included. The largest difference generally occurs during off peak hours, especially at hours beginning 1 and 2. The smallest difference generally occurs during peak hours, especially at hours beginning 9 and 10.

Figure 3-17 Difference between day-ahead and real-time hourly average physical load by hour of the day (Average hourly volumes): January through September, 2021 through 2025

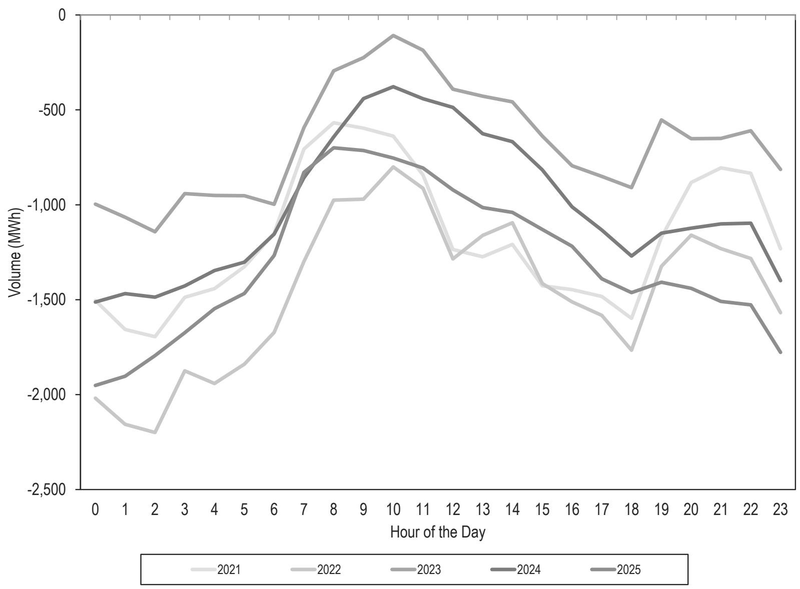


Figure 3-18 shows the difference between the day-ahead and real-time on peak and off peak hourly average physical load by month. DECs, UTCs and exports are not included.

Figure 3-18 Difference between day-ahead and real-time on peak and off peak hourly average physical load by month: 2021 through September 2025

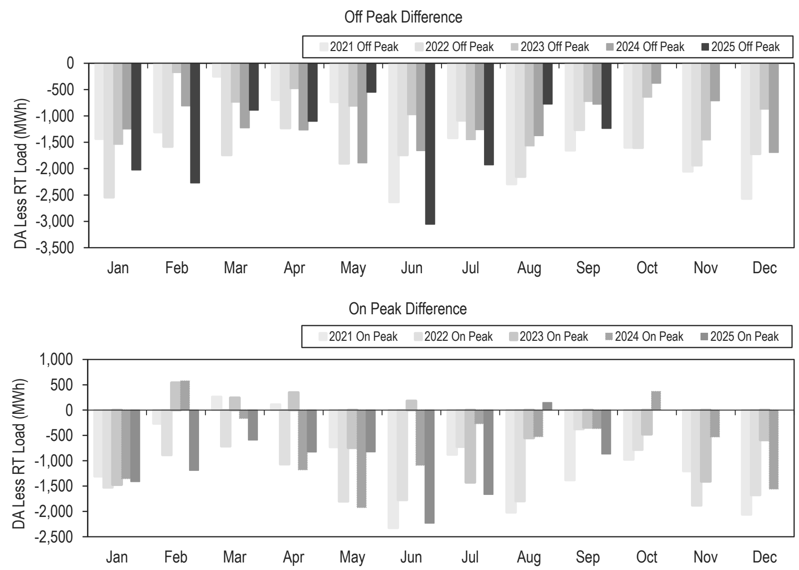


Table 3-11 shows the difference between the day-ahead and real-time on peak and off peak physical load by zone. DECs, UTCs and exports are not included. Some zones showed larger difference than other zones, such as DOM, BGE and APS. Some zones did not show a big difference between on peak and off peak, such as DOM and AEP. Some zones showed a significant difference between on peak and off peak, such as AECO and JCPL.

Table 3-11 Difference between day-ahead and real-time on peak and off peak physical load by zone

	2024 Jan-Sep				2025 Jan-Sep			
	Off Peak		On Peak		Off Peak		On Peak	
Zone	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load
AECO	16.99	1.8%	44.29	4.2%	(8.22)	(0.1%)	10.16	2.3%
AEP	(109.20)	(0.8%)	(81.44)	(0.5%)	(48.63)	(0.2%)	(11.11)	0.0%
APS	(93.39)	(1.7%)	(8.72)	(0.1%)	(70.30)	(1.1%)	1.52	0.2%
ATSI	(110.02)	(1.4%)	42.02	0.7%	(41.47)	(0.3%)	50.52	0.8%
BGE	(140.25)	(4.2%)	(149.69)	(3.8%)	(135.72)	(3.8%)	(141.70)	(3.3%)
COMED	7.72	0.3%	17.77	0.4%	(29.43)	(0.1%)	(56.16)	(0.2%)
DAY	(13.32)	(0.4%)	(7.73)	(0.1%)	(19.40)	(0.8%)	(14.16)	(0.4%)
DOM	(431.64)	(3.3%)	(447.02)	(3.0%)	(745.43)	(5.2%)	(793.17)	(5.0%)
DPL	(34.17)	(1.7%)	(27.54)	(1.0%)	(41.63)	(2.0%)	(36.49)	(1.3%)
DUQ	9.48	0.7%	28.14	1.7%	6.71	0.8%	38.24	2.8%
EKPC/DEOK	(46.52)	(0.9%)	(25.67)	(0.4%)	(32.76)	(0.6%)	13.91	0.3%
JCPL	(40.13)	(1.4%)	50.50	3.1%	(44.18)	(1.5%)	17.25	1.7%
METED	9.96	0.9%	26.12	1.6%	15.14	1.3%	26.30	1.7%
PECO	(28.69)	(0.5%)	(29.31)	(0.3%)	(27.61)	(0.4%)	(6.59)	0.1%
PENELEC	(7.48)	(0.3%)	9.79	0.6%	(3.60)	0.1%	12.51	0.9%
PEPCO	(114.28)	(3.9%)	(117.52)	(3.3%)	(107.71)	(3.4%)	(94.98)	(2.4%)
PPL	33.72	1.0%	81.15	1.8%	(29.14)	(0.5%)	4.38	0.4%
PSEG	(173.35)	(3.6%)	(93.10)	(1.3%)	(142.36)	(2.9%)	(63.51)	(0.6%)
RECO	(5.37)	(3.8%)	(6.05)	(2.9%)	0.53	0.5%	1.41	1.2%

Table 3-12 shows the difference between the day ahead and real-time physical load by zone for the last five years. DECs, UTCs and exports are not included. Some zones showed a change from year to year, such as AECO, PEPCO. The largest difference between day ahead load and real time load was in DOM with -767.70 MW, -5.1 percent of real-time load in the first nine months of 2025.

Table 3-12 Difference between day ahead and real-time physical load by zone: January through September, 2021 through 2025

	2021 Jan-Sep		2022 Jan-Sep		2023 Jan-Sep		2024 Jan-Sep		2025 Jan-Sep	
Zone	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load
AECO	(40.02)	(2.2%)	(41.73)	(2.2%)	9.39	1.3%	29.75	2.9%	0.36	1.0%
AEP	(98.79)	(0.7%)	(134.42)	(1.0%)	(73.93)	(0.4%)	(96.23)	(0.7%)	(31.13)	(0.1%)
APS	(54.33)	(0.9%)	(97.87)	(1.7%)	(109.05)	(1.9%)	(53.83)	(0.9%)	(36.80)	(0.5%)
ATSI	(15.12)	0.1%	(101.32)	(1.2%)	16.05	0.4%	(38.98)	(0.4%)	1.44	0.2%
BGE	(147.61)	(3.9%)	(93.35)	(2.6%)	(80.01)	(2.3%)	(144.66)	(4.0%)	(138.51)	(3.6%)
COMED	(20.41)	0.2%	(53.20)	(0.3%)	144.35	1.5%	12.41	0.3%	(41.90)	(0.2%)
DAY	(1.20)	0.2%	(37.57)	(1.7%)	20.59	1.3%	(10.71)	(0.3%)	(16.96)	(0.6%)
DOM	(506.75)	(4.2%)	(601.12)	(4.8%)	(626.85)	(4.9%)	(438.82)	(3.2%)	(767.70)	(5.1%)
DPL	(49.14)	(2.1%)	(65.47)	(3.0%)	(29.24)	(1.3%)	(31.07)	(1.4%)	(39.23)	(1.6%)
DUQ	4.69	0.5%	(90.70)	(5.7%)	24.98	1.8%	18.20	1.1%	21.42	1.7%
EKPC/DEOK	(46.49)	(0.8%)	(76.47)	(1.6%)	(42.19)	(0.8%)	(36.78)	(0.7%)	(10.99)	(0.2%)
JCPL	(35.47)	(0.5%)	(39.26)	(0.7%)	16.34	1.2%	2.22	0.7%	(15.52)	(0.0%)
METED	(19.17)	(0.7%)	(62.02)	(3.1%)	17.85	1.2%	17.51	1.2%	20.34	1.5%
PECO	(39.69)	(0.4%)	83.77	2.1%	50.05	1.5%	(28.98)	(0.4%)	(17.80)	(0.2%)
PENELEC	9.41	0.5%	10.90	0.6%	33.71	1.9%	0.59	0.1%	3.92	0.5%
PEPCO	(18.32)	(0.2%)	(20.31)	(0.6%)	(38.30)	(1.0%)	(115.80)	(3.6%)	(101.77)	(2.9%)
PPL	(46.75)	(0.8%)	32.06	0.9%	64.64	1.6%	55.88	1.4%	(13.50)	(0.1%)
PSEG	(43.63)	(0.7%)	(57.58)	(0.8%)	(59.41)	(1.1%)	(135.86)	(2.5%)	(105.58)	(1.8%)
RECO	6.47	4.3%	(1.53)	(0.9%)	(0.60)	0.3%	(5.69)	(3.4%)	0.94	0.8%

Market Behavior

Generator Offers

Generators indicate their availability for commitment and dispatch in the day-ahead market through their offers. Commitment availability status is economic, must run, or unavailable. Dispatch availability is defined by the difference between the economic minimum and maximum output levels. PJM will clear units that select must run status in the offer in the day-ahead market up to their economic minimum MW regardless of economics. Units may set their economic minimum MW equal to their economic maximum MW, also called block loading, or they may raise the economic minimum MW to a point between the actual economic minimum and the economic maximum. Must run units may commit at economic minimum and permit the balance to be dispatchable or block load the full output of the unit. If units select economic commitment status, the day-ahead market will determine whether to commit them based on their offers.

The Must Run column in Table 3-13 is the submitted offer MW of units offering with must run commitment status. The Eco Min column in Table 3-13 is the economic minimum MW of units offering with economic commitment status. The dispatchable range in Table 3-13 is the percent of MW offered by price range, between the economic minimum MW and economic maximum MW for all available units. Some units, like wind and solar, offer a dispatchable range in the day-ahead market although their availability in real time is determined by the presence of sun and wind rather than economics.

Units may designate all or a portion of their capacity as emergency MW.[38] Table 3-13 shows that 0.1 percent of offered MW are emergency MW. In some cases, higher shares of emergency MW result from offer behavior that does not accurately represent the availability of the emergency MW in real time.

In the day-ahead market for the first nine months of 2025, 22.4 percent of MW were offered as must run, 33.0 percent of MW were offered as the economic minimum MW for dispatchable units, 44.4 percent of MW were offered as dispatchable, and 0.1 percent of MW were offered as emergency maximum MW.

Table 3-13 Dispatchable status of day-ahead energy offers: January through September, 2025

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency MW	Dispatchable Percent
CC	9.2%	34.9%	0.4%	30.9%	14.2%	2.8%	1.3%	3.2%	2.6%	0.2%	0.1%	0.1%	0.1%	55.8%
CT	0.4%	58.4%	0.1%	2.7%	12.0%	7.0%	3.9%	9.9%	4.9%	0.3%	0.0%	0.1%	0.3%	40.9%
Diesel	0.0%	87.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.3%	-0.0%	0.0%	-0.0%	0.0%	12.3%
Hydro	81.7%	0.6%	17.7%	0.0%	-0.0%	0.0%	-0.0%	0.0%	0.0%	-0.0%	-0.0%	0.0%	0.0%	17.7%
Nuclear	83.6%	14.8%	1.8%	-0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
Solar	14.1%	0.1%	68.9%	7.2%	4.7%	2.0%	0.7%	1.0%	0.6%	0.4%	0.0%	0.4%	0.0%	85.8%
Steam - Coal	27.0%	27.3%	0.1%	13.3%	24.7%	3.2%	0.7%	0.3%	0.9%	2.3%	0.0%	0.0%	0.2%	45.5%
Steam - Other	5.4%	22.8%	2.1%	14.6%	15.5%	7.6%	1.5%	11.3%	18.4%	0.5%	0.0%	0.0%	0.1%	71.7%
Wind	1.6%	0.1%	73.1%	7.9%	8.2%	2.3%	3.1%	0.7%	1.2%	1.2%	0.1%	0.5%	0.0%	98.3%
Other	12.9%	51.6%	4.8%	4.8%	7.2%	0.1%	0.1%	1.4%	15.9%	0.5%	0.0%	0.0%	0.6%	34.9%
All Units	22.4%	33.0%	3.1%	15.2%	12.6%	3.6%	1.6%	4.2%	3.5%	0.5%	0.0%	0.1%	0.1%	44.4%

38 "PJM Manual 11: Energy & Ancillary Services Market Operations," Rev. 136. (Oct. 1, 2025). § 2.3.3.2 (Generator Schedules) "Designation of all or part of a unit's capacity as Maximum Emergency (ME) constitutes withholding in the Day-ahead Market, if The capacity is not designated as ME in the bid for the Real-time Market, or; There is no physical reason to designate the unit as ME."

Hourly Offers and Intraday Offer Updates

All participants may make specific hourly offers. Hourly offers mean that participants can specify different MW and price pairs for each hour of the day. Hourly offers can be submitted in the day-ahead market and offers may be updated in the real-time market. Participants must opt in on a monthly basis to make intraday offer updates in real time. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Units typically use hourly offers to reflect the two gas days in a power day. A gas day is from 10:00 AM EPT to 10:00 AM EPT the next day. Therefore, gas fired units may face two different gas prices. Typically, gas units have one offer from 00:00 EPT until 10:00 EPT and a different offer from 10:00 EPT until 24:00 EPT. Units typically use intraday updates to reflect changes in gas costs that occur in real time.

Table 3-14 shows the daily average number of units that make hourly offers in the day-ahead market, that opted in to intraday offer updates and that make intraday offer updates. In the first nine months of 2025, an average of 373 units per day made hourly offers, an increase of seven units from the first nine months of 2024. In the first nine months of 2025, 612 units opted in for intraday offer updates, an increase of 26 units from the first nine months of 2024. In the first nine months of 2025, an average of 163 units made intraday offer updates each day, an increase of 15 units from the first nine months of 2024.

Table 3-14 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through September, 2024 and 2025

	Fuel Type	2024 (Jan-Sep)	2025 (Jan-Sep)	Difference
Hourly Offers	Natural Gas	321	322	1
	Other Fuels	45	51	6
	Total	366	373	7
Opt In	Natural Gas	434	435	1
	Other Fuels	152	177	25
	Total	586	612	26
Intraday Offer Updates	Natural Gas	144	160	16
	Other Fuels	4	3	(1)
	Total	148	163	15
Total Units with nonzero offers		834	851	17

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[39] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement. The categorical exemption for intermittent resources, capacity storage resources, and hybrid resources from the capacity market must offer requirement was eliminated in February 2025.[40] Only demand resources are exempt from the capacity market must offer requirement.

The MMU recommends that all capacity resources have a must offer obligation. The MMU also recommends that performance penalties not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. This would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory, in contrast to PJM's current treatment of such resources.

The current enforcement of the ICAP must offer requirement is inadequate.[41] The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

Resources are required to submit their available capacity in three different systems. Resources are required to make offers in the energy market via Markets Gateway. Resources are required to report outages in the Dispatch Application Reporting Tool (eDART) in advance or in real time. Resources are required to report outages in the Generator Availability Data System (eGADS)

39 OA Schedule 1 § 1.10.1A(d).
40 FERC approved extending the RPM must offer requirement to intermittent resources, capacity storage resources, and hybrid resources but not to demand resources on February 20, 2025. 190 FERC ¶ 61,117.
41 PJM compares the data submitted in eDART to the data submitted in Markets Gateway using the eDART Gen Checkout. Generators are supposed to acknowledge their Gen Checkout reports. Manual 10 and the eDART User Guide do not specify what acknowledging the Gen Checkout report means, any requirements to acknowledge the Gen Checkout report or any consequences for not doing so. Gen Checkout is also only triggered if generators fail by more than defined thresholds.

after the fact. The three applications are not linked and there is no formal process to ensure consistency.

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are not reported as outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORd.

The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate.

The MMU recommended that intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. In 2023, the MMU and PJM proposed to require intermittent resources to offer their median forecast on an hourly basis in the day-ahead and real-time energy market. This proposal was implemented on November 15, 2023.[42]

The MMU recommends that storage resources also be subject to an enforceable ICAP must offer requirement that reflects the limitations of these resources.

Table 3-15 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first nine months of 2025. On average for all hours, 1,905 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours, 3,098 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that trigger scarcity pricing and larger than most supply contingencies that lead to synchronized reserve events.

42 *See* "Renewable Dispatch Markets Manual Changes," PJM presentation to the Markets and Reliability Committee. (November 15, 2023) <https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20231115/20231115-consent-agenda-f---1-manual-11-revisions---renewable-dispatch---presentation.ashx>.

Table 3-15 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: January through September, 2025

Month	90th Percentile	Average	10th Percentile
Jan-25	2,872	1,833	956
Feb-25	2,859	2,140	1,488
Mar-25	3,418	2,690	1,996
Apr-25	3,540	2,682	1,801
May-25	3,691	2,880	2,237
Jun-25	1,870	1,358	864
Jul-25	2,390	1,820	1,426
Aug-25	1,242	923	578
Sep-25	1,121	815	533
2025	3,098	1,905	798

The outage data reported in eGADS do not exactly match the energy market data submitted in Markets Gateway. For example, economic maximum MW levels submitted in Markets Gateway that reflect expected ambient conditions (including ambient derates) can be inconsistent with the maximum capability submitted in eGADS. Another example is the start and end times of planned outages in the shoulder months. In many situations units are derated in Markets Gateway to reflect an upcoming planned outage for which the unit must ramp down over an extended period but in eGADS the outage start time is not reported until the unit is completely unavailable. These differences can result in units not meeting their ICAP must offer requirement.

The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS.

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals emergency maximum MW. The PJM market rules allow generators to include emergency maximum MW as part of ICAP offered in the capacity market.[43]

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[44]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[45] Capacity resources should offer their full output in the energy market and be subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation.

Table 3-16 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in July 2025, 10 percent of hours had maximum emergency MW greater than or equal to 701 MW while 10 percent of hours had maximum emergency MW less than 227 MW. The hourly average, in the first nine months of 2025, was 344 MW offered as maximum emergency, 38.6 percent lower than in the first nine months of 2024.

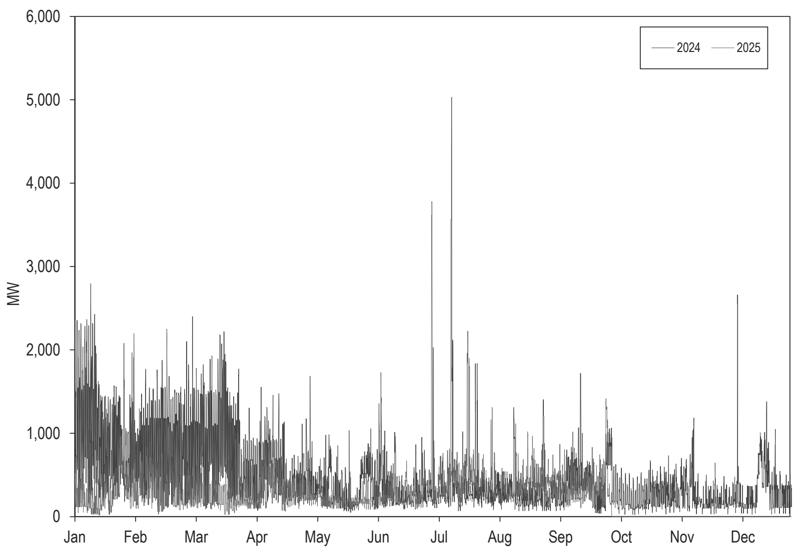
Table 3-16 Maximum emergency MW by month: January through September, 2025

Month	90th Percentile	Average	10th Percentile
Jan-25	680	338	97
Feb-25	728	399	120
Mar-25	430	254	97
Apr-25	601	350	165
May-25	307	214	130
Jun-25	464	280	154
Jul-25	701	506	227
Aug-25	551	384	258
Sep-25	592	377	189
2025	589	344	140

Figure 3-19 shows maximum emergency MW by hour in 2024 and the first nine months of 2025. The continued reduction of the use of emergency maximum that started in 2024 is mainly a result of improved compliance with the maximum emergency rules. The increases in maximum emergency MW are typically from short term situations at generators, such as testing of equipment which can be suspended in the event of a system emergency or operational restrictions such as limited run hours due to environmental permits.

43 See 151 FERC ¶ 61,208 at P 476 (2015).
44 OA Schedule 1 § 1.10.1A(d).
45 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

Figure 3-19 Maximum Emergency MW by hour: 2024 and January through September, 2025



Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

Price-Based Offers

All capacity resources that choose to make price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). The prices in a price-based PLS offer are at the discretion of the seller but the parameters are the same parameters used in the cost-based offers. For capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared.

Offer Schedule Selection

PJM's current process for selecting unit offers (schedules) does not prevent the exercise of market power through the use of markups or through the use of inflexible parameters. The goal of having parameter limited offers is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. The goal of having cost-based offers is to prevent the use of markups to exercise market power. Instead of ensuring the least cost solution, PJM frequently chooses the higher price-based schedule that includes no parameter limits rather than the cost-based schedule that includes parameter limits when a resource fails the TPS test. The result is that PJM does not select the lowest cost schedule and allows market power to be exercised. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021, but did not take corrective action in its November 30, 2023 order.[46] [47]

PJM raised the schedule selection issues in the stakeholder process to address computational time in the day-ahead market. PJM's original proposal would have weakened market power mitigation. FERC rejected PJM's proposal because PJM's proposal would create the ability for market sellers to exercise market power.[48] PJM filed and, on October 25, 2024, FERC accepted a revised proposal that would require that sellers that fail the TPS test be offer capped at their cost-based offers and that operating parameters be mitigated.[49] FERC accepted PJM's proposal that has no specific plans to implement the improved rules and instead links implementation to PJM's long delayed improvements to its combined cycle modelling. PJM's revised proposal also continues to use the flawed formula, which was the basis for the first proposal rejected

46 See 175 FERC ¶ 61,231 (2021).
47 See 185 FERC ¶ 61,158 (2023).
48 See 187 FERC 61,051 at P 25 (2024).
49 See 189 FERC ¶ 61,060 (2024).

by FERC, to select among cost-based offers. This will result in the illogical selection of cost-based offers in some circumstances, for example if a dual fuel unit submits offers for both oil and gas on a day when the economics change between the two fuels midday. PJM should modify its implementation to address that issue. The result would allow market sellers to select the correct cost-based fuel schedule. There is no reason to delay implementation until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The new approach should be implemented as soon as possible.

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first nine months of 2025. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[50] Table 3-17 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-17 shows that 29.3 percent of unit hours for units that failed the day-ahead TPS test were committed on price-based schedules that were less flexible than their cost-based schedules. For effective market power mitigation there would be zero units that fail the TPS test committed with parameters less flexible than their cost-based schedules.

Table 3-17 Parameter mitigation for units failing the day-ahead TPS test: January through September, 2025

Day-ahead Commitment For Units That Failed TPS Test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	20,721	29.3%
Committed on price schedule as flexible as cost	3,953	5.6%
Committed on cost (cost capped)	43,515	61.6%
Committed on price PLS	2,447	3.5%
Total committed on schedule as flexible as cost	49,915	70.7%
Total failed TPS test commitments	70,636	100.0%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in zones with a cold weather alert, a hot weather alert, or a maximum generation emergency declaration in the first nine months of 2025. PJM declared cold weather alerts on 13 days and hot weather alerts on 18 days in the first nine months of 2025. The analysis includes units with technologies that are subject to parameter limits, with a capacity commitment, in the zones where the cold or hot weather alerts were declared. Table 3-18 shows that 31.2 percent of unit hours during weather alerts in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules. Effective market power mitigation would result in zero units committed during cold and hot weather alerts with parameters less flexible than their price PLS schedules.

Table 3-18 Parameter mitigation during weather alerts: January through September, 2025

Day-ahead Commitment During Hot And Cold Weather Alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	51,165	31.2%
Committed on price schedule as flexible as PLS	10,808	6.6%
Committed on cost (cost capped)	8,135	5.0%
Committed on price PLS	93,923	57.3%
Total committed on schedule as flexible as PLS	112,866	68.8%
Total weather alert commitments	164,031	100.0%

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The best solution to the use of inflexible parameters is to require the use of flexible parameters in all offers at all times for capacity resources. Capacity resources are paid to be flexible but that payment will not result in flexible offers in the energy market, the only place it matters, unless there are explicit requirements that energy offers from capacity resources incorporate that flexibility.

50 Nuclear, wind, solar and hydro units are not subject to parameter limits.

The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times.

If flexible parameters are not required at all times, the use of flexible parameters should be required whenever a unit fails the TPS test and whenever the system is facing weather alerts or emergency conditions. PJM should always use cost-based offers for units that fail the TPS test, and always use flexible parameters in all price-based offers during weather alerts and emergencies. This approach would allow PJM to effectively mitigate inflexible operating parameters consistent with PJM's asserted processing time constraints. PJM's revised schedule selection proposal adopts this approach, but PJM has failed to propose an implementation date and the flawed rules remain in place as a result.

The MMU recommends that in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during cold and hot weather alerts and emergency conditions.[51] [52]

Parameter Limits

The unit specific parameter limits for capacity resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity resources by submitting supporting documentation which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for boiler based steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and a best practices equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[53] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have unit specific adjustments for some of the parameters. Table 3-19 shows, for the delivery year beginning June 1, 2025, the number of units with approved unit specific parameter limits, and the number of units that used the default parameter limits published by PJM.

51 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.
52 *See* "Schedule Selection: IMM Package," IMM Presentation to the Markets Implementation Committee (September 6, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>.
53 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx>.

Table 3-19 Adjusted unit specific parameter limit statistics: 2025/2026 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	117	37	24.0%
Frame CT	149	106	41.6%
Combined Cycle	94	28	23.0%
Reciprocating Internal Combustion Engines	56	3	5.1%
Solid Fuel NUG	32	6	15.8%
Oil and Gas Steam	10	22	68.8%
Subcritical and Supercritical Coal Steam	7	64	90.1%
Total	465	266	36.4%

Parameter Limited Schedule Exceptions

There are three different types of exceptions to the parameter limited schedule default values: temporary exceptions, period exceptions, and persistent exceptions, each differentiated by the length of time it applies. Market sellers must submit requests for exceptions to PJM and the MMU for approval, along with data and documentation. Valid exceptions must be based on physical operational or contractual limits.[54]

There are no defined consequences for real-time exceptions for units that change their parameters but do not meet the requirements in the tariff. Units that override their turn down ratio (economic maximum divided by economic minimum) either use PJM's fixed gen flag or simply increase their hourly economic minimum.[55] The turn down ratio has a defined parameter limit, but the limit can be evaded by the use of the fixed gen flag. These resources override their output limit parameters with no consequence.

The MMU has proposed that such a unit should not be paid a portion of its capacity market revenues, the daily value for each day, if it fails to include its defined parameter values in its offer (by either using the fixed gen option or increasing their economic minimum). The MMU recommends that PJM require generators to request temporary parameter exceptions for the use of the fixed gen flag. The request process requires generators to demonstrate that the request is based on a physical and actual constraint.

Consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, resources that operate with a denied temporary parameter limit exception should not be paid the corresponding portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that capacity resources are paid for their capacity only when they meet their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.[56]

Generator Flexibility Incentives in the Capacity Market

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to submit operating parameters to the market based not just on the resource physical constraints, but also based on other constraints, such as contractual limits.[57] The order primarily addressed limits imposed by natural gas pipelines. The Commission directed PJM to revise its tariff to establish a process through which capacity performance resources that operate outside the defined unit specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[58]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of mitigating the performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners

54 *See* OA Schedule 1 § 6.6(i) and PJM Manual 11, Section 2.3.4.3.
55 PJM Markets Gateway User Guide, Section 5.8: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 54, Section 14.3 Submit Revised MW Operating Limits at 138 and Section 14.4 Revise the Status of a Generating Unit at 139 <https://www.pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.
56 *See* Monitoring Analytics LLC, "Real-Time Values," presented at the Markets Implementation Committee Special Session (October 7, 2020) at 12, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201007/20201007-item-06b-real-time-values-imm.ashx>.
57 See 151 FERC ¶ 61,208 at P 437 (2015).
58 *Id.* at P 440.

to establish unit parameters based on nonphysical limits, the June 9th Order weakened the incentives for units to be flexible and weakened the assignment of performance risk to generation owners. Contractual limits and the option to choose from a range of gas pipeline tariff provisions, unlike generating unit operational limits, are a function of the interests and incentives of the generators making the choices. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The approach to parameters defined in the June 9th Order will increase energy market uplift payments substantially. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market reference resource used for the Cost of New Entry (CONE) calculation for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and more recently, also during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. The frequency of 24 hour minimum run time requests increased after Winter Storm Elliott in December 2022. Table 3-20 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In the first nine months of 2025, there were 93 units in PJM with a total installed capacity of 11,137 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-20 Units with 24 hour minimum run times due to gas pipeline restrictions: January 2018 through September 2025

Year	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2018	25	3,627
2019	37	5,616
2020	13	3,873
2021	61	7,514
2022	81	10,019
2023	75	9,824
2024	79	10,476
2025	93	11,137

The increase in units requesting 24 hour minimum run times is a result of pipelines enforcing the pipeline tariff ratable take provisions. Pipelines have the authority to require ratable takes under their tariffs at any time although pipelines do not enforce ratable takes on a routine basis. Some generators have also requested extremely long notification times based on pipeline nomination deadlines. (See Table 3-66.) When pipelines enforce these deadlines, generators cannot obtain gas to flow for a given market hour once the deadline has passed for that hour and therefore they cannot start according to their normal notification plus start times (normally less than 30 minutes). For example, at 1700 EPT, the next nomination cycle is intraday 3 (ID3). The ID3 deadline is 2000 EPT for gas to flow starting at 2300 EPT.

When these nomination deadlines are enforced, at 1700 EPT, a gas unit can only start at 2300 EPT (or in 6 hours). This effectively increases the time to start (notification time plus start time) from 30 minutes to 6 hours. The long notification times make the units unavailable for commitment in ITSCED and the units can only be committed manually in real time. Generators may request temporary exceptions based on pipeline restrictions in order to provide PJM with offers that accurately reflect their capabilities. Units operating inflexibly due to pipeline restrictions are eligible for uplift. Temporary exceptions should be limited to the duration of restrictions imposed by pipelines.

In the first nine months of 2025, PJM paid $147.7 million in day ahead uplift to gas fired units with a 24 hour minimum run time, primarily during the 2025 Polar Vortex. PJM paid an additional $30.9 million in balancing uplift for real-time commitments of units with a 24 hour minimum run time in the first nine months of 2025, with $15.0 million paid to units during the 2025 Polar Vortex.

After observing the misuse of and the failure to use temporary exceptions during Winter Storm Elliott, on September 8, 2023, PJM and the MMU posted guidelines for the correct use of temporary exceptions for pipeline related restrictions. The guidelines detail exactly how units should use temporary exceptions to reflect pipeline restrictions in units' minimum run time, notification time and turn down ratio parameters.[59] During Winter Storm Elliott (December 22-24, 2022), 71 units on average (totaling 8,791 MW) requested temporary exceptions due to pipeline restrictions. During Winter Storm Gerri (January 16-18, 2024), 96 units on average (totaling 13,462 MW) requested temporary exceptions due to pipeline restrictions. During the 2025 Polar Vortex (January 18-23, 2025) 115 units on average (totaling 17,635 MW) requested exceptions due to pipeline restrictions.

The MMU recognizes that pipeline restrictions must be reflected in units' operating parameters in order for PJM to properly schedule and manage the system but it is important to prevent abuse through the submission of inflexible parameters not based on actual constraints. The MMU recommends that PJM only approve temporary exceptions that are based on pipeline tariff terms and/or pipeline notices when actually enforced by the pipelines.

Virtual Offers and Bids

Market participants may make virtual offers and bids in the PJM Day-Ahead Energy Market, and such offers and bids may be marginal.

Any market participant in the PJM Day-Ahead Energy Market may use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[60] Up to congestion transactions may be submitted between any two aggregates on a list of 46 aggregates eligible for up to congestion transaction bidding.[61] Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-20 shows an example of the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2025.

59 *See* "Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions" PJM and MMU memorandum to PJM Market Participants (September 8, 2023) <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter_Limit_(PLS)_Exceptions_due_to_Pipeline_Restrictions_20230908.pdf>.

60 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).

61 Prior to November 1, 2012, market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Figure 3-20 Day-ahead aggregate supply curves: 2025 example day

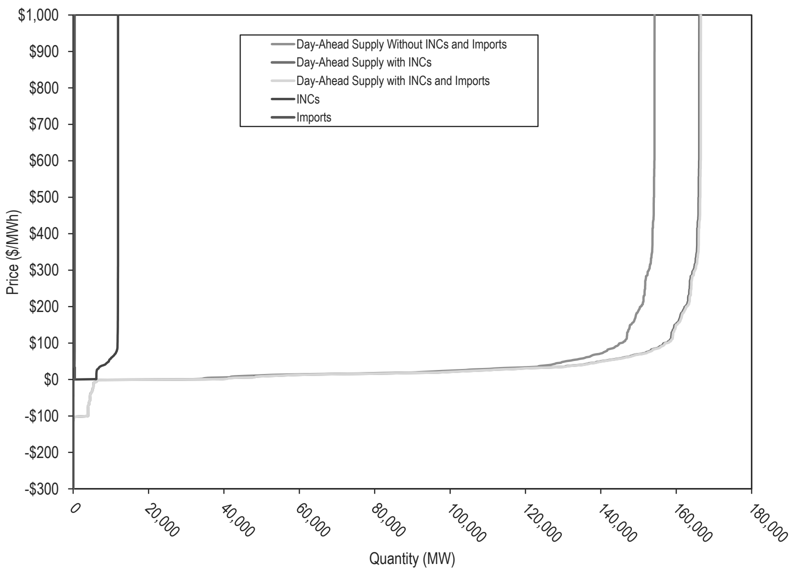


Table 3-21 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2024 and the first nine months of 2025.[62] The hourly average submitted increment offer MW increased by 4.6 percent and cleared increment MW increased by 8.4 percent in the first nine months of 2025 compared to the first nine months of 2024. The hourly average submitted decrement bid MW increased by 17.7 percent and cleared decrement MW increased by 2.6 percent in the first nine months of 2025 compared to the first nine months of 2024.

Table 3-21 Average hourly number of cleared and submitted INCs and DECs by month: January 2024 through September 2025

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2024	Jan	4,660	10,515	402	1,499	5,161	11,668	287	1,113
2024	Feb	5,716	12,429	487	1,789	5,063	10,952	275	1,039
2024	Mar	6,040	12,378	426	1,422	5,802	12,563	334	1,202
2024	Apr	5,848	11,972	480	1,248	5,055	11,940	385	1,204
2024	May	5,634	11,961	452	1,241	5,213	13,453	397	1,445
2024	Jun	4,627	10,503	420	1,176	5,468	13,163	362	1,290
2024	Jul	4,042	10,177	392	1,177	5,360	13,376	421	1,416
2024	Aug	3,802	9,767	373	1,107	6,269	13,946	496	1,432
2024	Sep	3,640	9,507	396	1,225	5,588	13,517	467	1,646
2024	Oct	5,091	11,262	509	1,530	4,351	13,985	424	1,946
2024	Nov	5,136	11,621	437	1,461	4,491	13,307	414	1,731
2024	Dec	5,570	12,681	479	1,705	5,686	15,190	493	2,037
2024	Annual	4,982	11,228	438	1,381	5,295	13,101	397	1,461
2025	Jan	6,024	12,413	535	1,821	5,068	14,037	420	1,914
2025	Feb	6,207	12,420	566	1,868	5,152	14,703	444	2,089
2025	Mar	6,239	12,836	603	1,920	5,177	15,163	464	2,262
2025	Apr	6,142	12,604	584	1,679	4,343	14,247	486	2,124
2025	May	5,007	10,837	543	1,480	4,947	13,199	452	1,703
2025	Jun	4,130	10,385	466	1,435	6,310	16,189	570	2,171
2025	Jul	4,609	10,299	481	1,366	6,414	15,731	541	2,262
2025	Aug	4,694	11,329	472	1,481	6,253	14,633	502	1,821
2025	Sep	4,679	10,619	536	1,653	6,606	17,145	591	2,464
2025	Jan-Sep	5,297	11,521	531	1,632	5,589	14,999	497	2,088

Table 3-22 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2024 and the first nine months of 2025. The hourly average submitted up to congestion bid MW decreased by 1.4 percent and cleared up to congestion bid MW decreased by 10.1 percent in the first nine months of 2025 compared to the first nine months of 2024.

62 Table 3-21 uses cleared day-ahead market data while final settlements data is used elsewhere in this report.

Table 3-22 Average hourly cleared and submitted up to congestion bids by month: January 2024 through September 2025

		Up to Congestion			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2024	Jan	13,905	35,217	787	1,667
2024	Feb	12,773	30,008	563	1,307
2024	Mar	14,401	37,663	600	1,432
2024	Apr	10,922	35,180	535	1,443
2024	May	9,073	29,896	627	1,567
2024	Jun	9,810	26,251	638	1,365
2024	Jul	8,721	27,022	757	1,532
2024	Aug	9,016	27,970	841	1,575
2024	Sep	10,489	31,088	782	1,631
2024	Oct	10,684	33,321	670	1,611
2024	Nov	9,093	30,131	533	1,438
2024	Dec	10,442	32,473	748	1,790
2024	Annual	10,774	31,366	675	1,532
2025	Jan	10,955	34,709	911	2,194
2025	Feb	12,000	34,801	798	2,034
2025	Mar	10,512	34,843	741	2,095
2025	Apr	8,415	29,420	610	1,999
2025	May	7,851	21,973	503	1,574
2025	Jun	11,046	32,384	791	2,071
2025	Jul	9,595	29,536	913	2,229
2025	Aug	9,019	25,911	669	1,802
2025	Sep	9,844	33,392	741	2,383
2025	Jan-Sep	9,894	30,719	742	2,041

Table 3-23 shows the average hourly number of day-ahead import and export transactions and the average hourly MW in 2024 and the first nine months of 2025.[63] In the first nine months of 2025, the average hourly submitted import transaction MW decreased by 10.9 percent and the average hourly cleared import transaction MW decreased by 11.4 percent compared to the first nine months of 2024. In the first nine months of 2025, the average hourly submitted export transaction MW increased by 16.4 percent and the average hourly cleared export transaction MW increased by 15.9 percent compared to the first nine months of 2024.

Table 3-23 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2024 through September 2025

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2024	Jan	322	394	4	5	4,561	4,590	33	34
2024	Feb	353	411	4	4	4,132	4,146	31	31
2024	Mar	345	375	5	5	3,912	3,917	34	35
2024	Apr	250	277	4	4	3,200	3,235	23	23
2024	May	400	422	5	5	2,812	2,828	21	21
2024	Jun	179	196	3	3	4,585	4,599	35	36
2024	Jul	304	344	4	5	3,820	3,850	27	28
2024	Aug	295	335	4	5	4,112	4,160	28	29
2024	Sep	258	275	4	5	3,387	3,474	25	26
2024	Oct	731	783	9	9	2,662	2,723	23	24
2024	Nov	477	650	6	8	2,695	2,716	26	26
2024	Dec	504	680	5	6	3,987	4,257	36	37
2024	Annual	375	434	5	5	3,655	3,708	29	29
2025	Jan	199	330	3	4	4,392	4,575	37	38
2025	Feb	355	403	5	6	4,948	4,992	41	42
2025	Mar	192	192	3	3	4,430	4,485	39	40
2025	Apr	366	384	5	6	3,789	3,821	26	27
2025	May	278	294	4	5	3,752	3,761	28	28
2025	Jun	193	215	3	4	4,426	4,467	33	34
2025	Jul	286	313	5	5	4,787	4,827	34	34
2025	Aug	213	242	4	5	5,232	5,268	39	40
2025	Sep	324	338	6	6	4,267	4,308	30	31
2025	Jan-Sep	267	300	4	5	4,445	4,499	34	35

Figure 3-21 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through September 2025. Cleared volumes were greater in 2023 than any year since 2020, when uplift charges for up to congestion transactions took effect on November 1, 2020. The monthly MW volume of UTC bids in April 2023 was at its highest level since 2017, but decreased significantly beginning May 2023 and has remained stable beginning August 2023 through September 2025.

63 Table 3-23 uses cleared day-ahead market data, while final settlements data is used elsewhere in this report.

Figure 3-21 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through September 2025

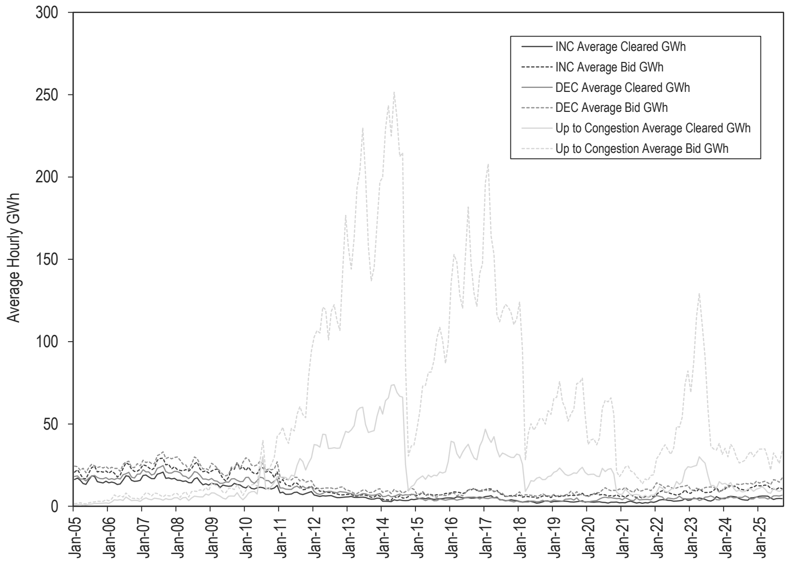
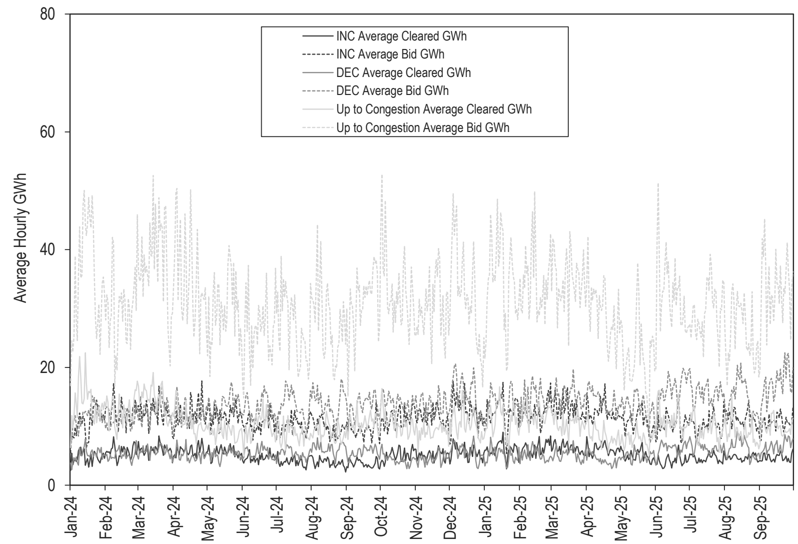


Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2024 through September 2025.

Figure 3-22 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2024 through September 2025



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial at an account level.[64] Physical entities are defined as individual accounts in PJM's settlement systems that take physical positions in PJM markets and typically include utilities and customers. Financial entities are defined as individual accounts in PJM's settlement systems that take financial positions in PJM markets and typically include banks and trading firms. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries. Financial entities' share of cleared MWh of INCs and DECs in the first nine months of 2025 increased to 97.2 percent from 95.3 percent in the nine months of 2024.

64 The MMU modified the method for categorizing participants as physical and financial participants. See the explanation in the *2025 Quarterly State of the Market Report for PJM: January through March*, Section 13: Financial Transmission Rights at Market Structure (May 8, 2025).

Table 3-24 shows, in the first nine months of 2024 and 2025, the total increment offers and decrement bids and cleared MW by organization type.

Table 3-24 INC and DEC bids and cleared MWh by organization type (MWh): January through September, 2024 and 2025

	2024 (Jan-Sep)				2025 (Jan-Sep)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	152,545,517	97.7%	64,764,225	95.3%	171,154,662	98.5%	69,297,250	97.2%
Physical	3,670,941	2.3%	3,165,336	4.7%	2,575,568	1.5%	2,012,997	2.8%
Total	156,216,457	100.0%	67,929,560	100.0%	173,730,230	100.0%	71,310,247	100.0%

Table 3-25 shows the total up to congestion bid and cleared MWh by organization type in the first nine months of 2024 and 2025. Up to congestion bids submitted by financial entities decreased in the first nine months of 2025 compared to the first nine months of 2024 from 200.3 million MWh to 196.2 million MWh, while up to congestion bids submitted by physical entities increased from 2.6 million MWh to 3.1 million MWh. Financial entities submitted 97.5 percent of all up to congestion bids, down from 97.8 percent, and cleared 95.2 percent of all up to congestion bids, down from 96.4 percent. In the first nine months of 2025, almost all up to congestion trading activity was by financial participants.

Table 3-25 Up to congestion transactions by organization type (MWh): January through September, 2024 and 2025

Year	Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
	Financial	200,264,451	97.8%	69,773,828	96.4%
2024 (Jan-Sep)	Physical	4,576,619	2.2%	2,587,200	3.6%
	Total	204,841,069	100.0%	72,361,028	100.0%
	Financial	196,170,605	97.5%	61,675,259	95.2%
2025 (Jan-Sep)	Physical	5,069,592	2.5%	3,139,560	4.8%
	Total	201,240,197	100.0%	64,814,819	100.0%
	Financial	(4,093,846)	(2.0%)	(8,098,569)	(11.6%)
(2025 minus 2024)	Physical	492,973	10.8%	552,361	21.3%
	Difference	(3,600,873)	(1.8%)	(7,546,209)	(10.4%)

Table 3-26 shows the total import and export transactions by organization type in the first nine months of 2024 and 2025.

Table 3-26 Import and export transactions by organization type (MWh): January through September, 2024 and 2025

		2024 (Jan-Sep)		2025 (Jan-Sep)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	13,827,436	51.0%	16,180,293	52.5%
	Physical	13,259,314	49.0%	14,622,339	47.5%
	Total	27,086,750	100.0%	30,802,631	100.0%
Real-Time	Financial	27,290,607	55.6%	31,378,872	57.6%
	Physical	21,824,068	44.4%	23,092,413	42.4%
	Total	49,114,676	100.0%	54,471,285	100.0%

Table 3-27 shows the top 10 locations by total cleared INC and DEC MWh in the first nine months of 2024 and 2025. The top 10 locations included four hubs, four interface pricing points, and two residual metered load aggregates. For generator pnodes not included in the top 10 by the sum of INCs and DECs, DAVISBES25 KV DB10 cleared the most INC volume of 486,147 MWh and REMNTNCT18 KV GT1 with the most DEC volume of 348,822 MWh in the first nine months of 2025.

Table 3-27 Virtual offers and bids by top 10 locations (MWh): January through September, 2024 and 2025

2024 (Jan-Sep)					2025 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
WESTERN HUB	HUB	2,690,189	1,569,874	4,260,064	MISO	INTERFACE	365,157	4,662,100	5,027,257
MISO	INTERFACE	109,155	3,814,561	3,923,716	WESTERN HUB	HUB	2,512,398	1,673,987	4,186,385
SOUTH	INTERFACE	2,459,609	425,520	2,885,130	SOUTH	INTERFACE	2,943,317	626,681	3,569,997
N ILLINOIS HUB	HUB	2,052,540	618,932	2,671,473	N ILLINOIS HUB	HUB	1,637,986	745,694	2,383,681
NYIS	INTERFACE	484,413	1,521,984	2,006,397	DOM_RESID_AGG	RESIDUAL METERED EDC	383,270	1,419,758	1,803,028
AEP-DAYTON HUB	HUB	842,250	939,372	1,781,622	NYIS	INTERFACE	553,310	1,223,893	1,777,203
DOM_RESID_AGG	RESIDUAL METERED EDC	192,190	1,226,010	1,418,200	AEP-DAYTON HUB	HUB	508,545	778,574	1,287,119
LINDENVFT	INTERFACE	22,936	1,233,117	1,256,053	LINDENVFT	INTERFACE	42,895	1,212,347	1,255,242
BGE_RESID_AGG	RESIDUAL METERED EDC	336,506	855,626	1,192,132	BGE_RESID_AGG	RESIDUAL METERED EDC	529,897	687,364	1,217,261
EASTERN HUB	HUB	294,056	637,935	931,992	CHICAGO HUB	HUB	572,186	544,995	1,117,180
Top ten total		9,483,844	12,842,932	22,326,777			10,048,962	13,575,392	23,624,354
PJM total		32,124,357	35,805,204	67,929,561			34,699,620	36,610,626	71,310,247
Top ten total as percent of PJM total		29.5%	35.9%	32.9%			29.0%	37.1%	33.1%

Table 3-28 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall profits on each path in the first nine months of 2024 and 2025. Total profits for up to congestion transactions in the first nine months of 2025 were $50.7 million, a 50.4 million increase compared to profits of $0.2 million in the first nine months of 2024.[65] The UTCs from DOMINION HUB to DOM_RESID_AGG constituted 10.7 percent of all UTC cleared volume in the first nine months of 2025, yielding a profit of $19.3 million.

Table 3-28 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through September, 2024 and 2025[66]

2024 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	8,177,178	$4,105,787	($4,654,145)	($3,885,209)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	3,764,134	($208,806)	$3,075,769	$1,723,175
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	3,524,261	($2,508,850)	$5,395,283	$1,385,851
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,999,891	($371,365)	$1,316,711	$276,483
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	1,759,904	$1,204,365	$587,718	$1,148,776
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,677,342	$2,861,186	($539,374)	$1,558,855
CHICAGO GEN HUB	HUB	MISO	INTERFACE	1,470,580	($582,713)	$266,317	($771,853)
CHICAGO GEN HUB	HUB	DEOK_RESID_AGG	AGGREGATE	1,183,341	$1,235,394	($261,925)	$466,324
CHICAGO GEN HUB	HUB	N ILLINOIS HUB	HUB	969,451	($2,774,095)	$4,060,549	$860,502
UGI_RESID_AGG	AGGREGATE	NYIS	INTERFACE	889,649	($799,717)	$1,147,864	($5,925)
Top ten total				25,415,732	$2,161,186	$10,394,768	$2,756,980
PJM total				72,361,028	$20,362,164	$10,501,009	$228,499
Top ten total as percent of PJM total				35.1%	10.6%	99.0%	1206.6%
2025 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MWh	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	6,934,245	$3,226,115	$19,595,592	$19,334,980
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,713,485	$3,830,128	($1,113,183)	$874,399
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,190,902	($163,051)	$2,321,086	$1,352,275
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,157,365	$837,321	$197,409	$509,159
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	1,131,621	($1,165,219)	$1,964,343	$44,367
AEP GEN HUB	HUB	AEPAPCO_RESID_AGG	AGGREGATE	707,058	$4,656,936	($1,321,860)	$2,190,725
CHICAGO GEN HUB	HUB	COMED_RESID_AGG	AGGREGATE	685,163	($374,408)	$947,193	$10,207
ATSI GEN HUB	HUB	DUQ_RESID_AGG	AGGREGATE	664,978	$1,352,792	($238,428)	$585,908
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	643,910	$17,870	$310,263	($20,645)
CHICAGO GEN HUB	HUB	N ILLINOIS HUB	HUB	630,880	($111,352)	$478,255	($9,830)
Top ten total				16,459,605	$12,107,132	$23,140,671	$24,871,544
PJM total				64,814,819	$34,925,370	$62,087,104	$50,664,308
Top ten total as percent of PJM total				25.4%	34.7%	37.3%	49.1%

65 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.
66 The columns "Source Revenue" and "Sink Revenue" are totals before uplift charges are subtracted. The column "UTC Profit" includes uplift charges, in addition to the source and sink revenue, and so is less than the sum of the revenue from each side of the transaction.

Table 3-29 shows the average daily number of distinct source-sink pairs that were offered and cleared each month from January 2024 through September 2025. The average number of submitted source-sink pairs per day increased from 1,212 source-sink pairs submitted in the first nine months of 2024 to 1,507 in the first nine months of 2025. The average number of cleared source-sink pairs per day increased from 907 in the first nine months of 2024 to 1,204 per day in the first nine months of 2025.

Table 3-29 Number of offered and cleared UTC source and sink pairs: January 2024 through September 2025

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2024	Jan	1,298	1,521	1,047	1,347
2024	Feb	1,166	1,364	810	991
2024	Mar	1,062	1,333	745	1,014
2024	Apr	1,095	1,414	788	1,021
2024	May	1,241	1,560	934	1,325
2024	Jun	1,194	1,528	969	1,377
2024	Jul	1,308	1,520	1,165	1,317
2024	Aug	1,265	1,572	1,129	1,486
2024	Sep	1,271	1,462	1,130	1,319
2024	Oct	1,363	1,563	1,176	1,363
2024	Nov	1,323	1,485	1,039	1,294
2024	Dec	1,418	1,729	1,167	1,486
2024	Annual	1,250	1,504	1,008	1,278
2025	Jan	1,454	1,641	1,222	1,490
2025	Feb	1,411	1,617	1,174	1,399
2025	Mar	1,523	1,844	1,278	1,641
2025	Apr	1,477	1,718	1,123	1,428
2025	May	1,360	1,597	938	1,325
2025	Jun	1,521	1,847	1,208	1,622
2025	Jul	1,680	1,852	1,380	1,654
2025	Aug	1,572	1,836	1,249	1,554
2025	Sep	1,554	1,766	1,257	1,497
2025	Annual	1,501	1,743	1,203	1,512

Table 3-30 and Figure 3-23 show total cleared up to congestion transactions and the share of the top 10 up to congestion paths by transaction type (import, export, wheel, or internal) in the first nine months of 2024 and 2025. Total cleared up to congestion transactions decreased by 10.4 percent from 72.3 million MWh in the first nine months of 2024 to 64.8 million MWh in the first nine months of 2025. Internal up to congestion transactions in the first nine months of 2025 were 85.0 percent of all up to congestion transactions, an increase from 83.5 percent in the first nine months of 2024.

Table 3-30 Cleared up to congestion transactions and share of top 10 paths by type (MW): January through September, 2024 and 2025

	2024 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,429,265	3,664,188	1,504,309	24,622,166	32,219,929
PJM total (MW)	4,617,138	5,670,164	1,624,775	60,448,950	72,361,028
Top ten total as percent of PJM total	52.6%	64.6%	92.6%	40.7%	44.5%
PJM total as percent of all up to congestion transactions	6.4%	7.8%	2.2%	83.5%	100.0%
	2025 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,714,664	1,563,471	886,913	16,459,605	21,624,653
PJM total (MW)	4,952,707	3,753,697	1,006,894	55,101,521	64,814,819
Top ten total as percent of PJM total	54.8%	41.7%	88.1%	29.9%	33.4%
PJM total as percent of all up to congestion transactions	7.6%	5.8%	1.6%	85.0%	100.0%

Figure 3-23 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through June 2025. An initial increase and continued increase in internal up to congestion transactions by month followed the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[67] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[68] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction.

UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[69] In 2022 and the first six months of 2023, the volume of cleared UTCs increased significantly, primarily internal transactions. The volume of cleared UTCs decreased consistently from July 2023 through September 2025.

67 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).

68 *Id.*

69 See 172 FERC ¶ 61,046 (2020).

Figure 3-23 Monthly cleared up to congestion transactions by type (GWh): January 2005 through September 2025

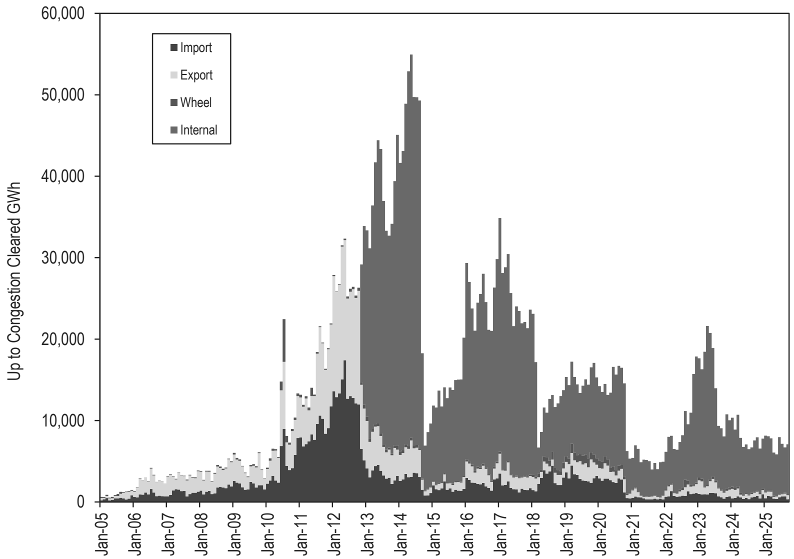
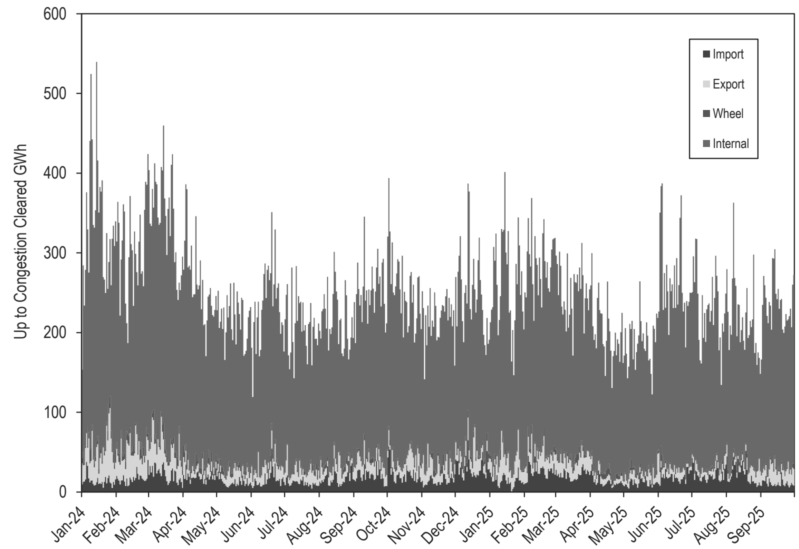


Figure 3-24 shows the daily cleared up to congestion GWh by transaction type from January 1, 2024, through September 30, 2025. In the first nine months of 2025, the total cleared GWh of import, export, and internal up to congestion transactions remained relatively unchanged compared to 2024.

Figure 3-24 Daily cleared up to congestion transaction by type (GWh): January 2024 through September 2025



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[70]

A key assumption underlying the February 2018 order was that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging

70 PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," Docket No. ER18-88, October 17, 2017 at 9–10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them…Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."

of prices over a large number of buses at aggregate nodes.[71] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time models since the February 2018 order.

The assumption that modeling differences are averaged out over the multiple individual nodes included in aggregate nodes does not hold for multiple aggregate nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For example, the MMU recommends eliminating UTC bidding at the following pricing points: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when the line ratings on constraints are violated and transmission penalty factors are applied in the real-time energy market. This occurs both when line ratings are actually violated and when PJM operators reduce the line ratings in SCED. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day-ahead and real-time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be significant, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads resulting from systematic modeling and operational differences between day-ahead and real-time affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

71 See 162 FERC ¶ 61,139 at PP 35–36 ("We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates.").

Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with shortage pricing, the creation of closed loop interfaces related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and transmission constraint penalty factors, and committing reserves beyond the requirement, or change price formation through fast start pricing.

The real-time average LMP in the first nine months of 2025 increased $14.57 per MWh, or 46.2 percent, from the first nine months of 2024, from $31.50 per MWh to $46.05 per MWh. The real-time load-weighted average LMP in the first nine months of 2025 increased $16.20 per MWh, or 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh.

The costs of fuel, emissions, and consumables, fundamental components of the real-time load-weighted average LMP, increased $9.85 per MWh from $19.75 per MWh in the first nine months of 2024 to $29.59 per MWh in the first nine months of 2025, or 60.8 percent of the increase in real-time load-weighted average LMP.

The day-ahead average LMP for the first nine months of 2025 increased $14.60 per MWh, or 47.0 percent from the first nine months of 2024, from $31.09 per MWh to $45.69 per MWh. The day-ahead load-weighted average LMP for the first nine months of 2025 increased $16.03 or 47.4 percent from the first nine months of 2024, from $33.85 per MWh to $49.88 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply curve.[72] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, to ensure that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[73]

LMP may, at times, be set by administratively defined transmission constraint penalty factors, which equal a default level of $30,000 per MWh in the day-ahead market dispatch run and $2,000 per MWh in the real-time market and in the day-ahead market pricing run. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. When this occurs, the shadow price of the constraint is set by transmission constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. However, PJM operator interventions to reduce the control limits on transmission constraint line ratings used in the market clearing unnecessarily trigger transmission constraint penalty factors and significantly increase prices. A competitive market does not require that prices increase when PJM artificially triggers transmission constraint penalty factors.

72 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2) at 19–27.

73 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

Fast Start Pricing: DLMP and PLMP

PJM implemented fast start pricing in both the day-ahead and real-time markets on September 1, 2021. Fast start pricing is based on an incorrect LMP calculation called the pricing run. The pricing run LMP (PLMP) is the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP). Unless otherwise specified, the LMP tables and figures show the PLMP for September 1, 2021, and after.

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously ignoring (relaxing) the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units must have notification time plus start time less than or equal to one hour; minimum run time less than or equal to one hour; and can set price only when online and running for PJM, not self scheduled.

The goal of fast start pricing is to allow inflexible resources to set prices based on the sum of their commitment costs per MWh and their marginal costs. The price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing.

PJM has also introduced other differences between the dispatch run and pricing run that are not related to fast start pricing. For example, in the day-ahead market, PJM uses a default $30,000 per MWh transmission constraint penalty factor in the dispatch run and a $2,000 per MWh transmission constraint penalty factor in the pricing run. Starting on October 1, 2022, PJM uses capping of the system marginal price only in the pricing run, which affected real-time market prices during Winter Storm Elliott in December 2022. On June 24, PJM capped the energy LMP in the pricing run at $3,700 per MWh for two five minute intervals in the hour beginning at 1800 and one five minute interval in the hour beginning at 1900. This system marginal price (SMP) capping process has not been reviewed by FERC or included in the PJM Operating Agreement.

DLMP and PLMP

Table 3-31 shows the day-ahead and real-time monthly load-weighted average PLMP and DLMP in 2024 and the first nine months of 2025.

The real-time load-weighted average PLMP was $50.51 per MWh for the first nine months of 2025, which is 9.0 percent, $4.17 per MWh, higher than the real-time load-weighted average DLMP of $46.34 per MWh.

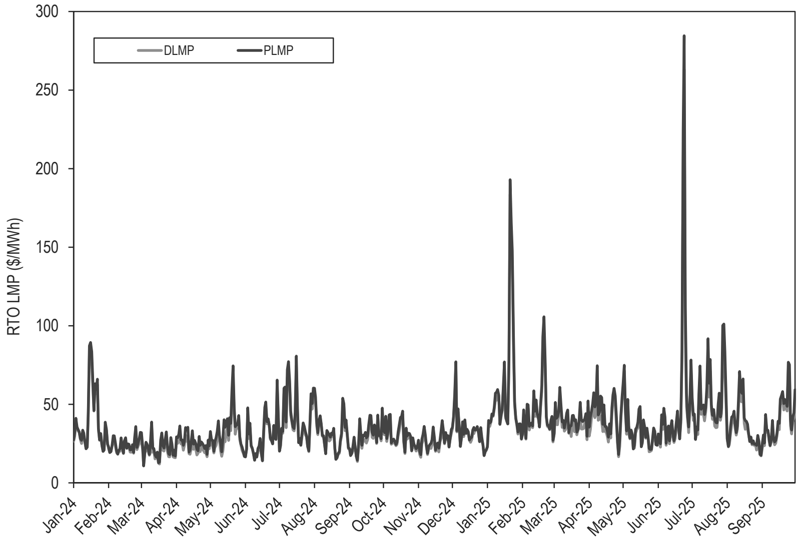
The day-ahead load-weighted average PLMP was $49.88 per MWh for the first nine months of 2025, which is 0.1 percent, $0.07 per MWh, higher than the day-ahead load-weighted average DLMP of $49.81 per MWh.

Table 3-31 Day-ahead and real-time load-weighted average DLMP and PLMP: 2024 through September 2025

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2024	Jan	$48.45	$48.65	$0.20	0.4%	$40.82	$42.78	$1.95	4.8%
2024	Feb	$23.67	$23.70	$0.03	0.1%	$23.20	$24.86	$1.66	7.2%
2024	Mar	$21.89	$21.93	$0.04	0.2%	$20.30	$23.15	$2.85	14.0%
2024	Apr	$26.73	$26.75	$0.02	0.1%	$23.29	$27.17	$3.87	16.6%
2024	May	$32.92	$32.90	($0.02)	(0.1%)	$31.70	$36.16	$4.46	14.1%
2024	Jun	$32.59	$32.62	$0.03	0.1%	$31.95	$33.35	$1.40	4.4%
2024	Jul	$44.51	$44.69	$0.18	0.4%	$44.12	$47.17	$3.04	6.9%
2024	Aug	$36.34	$36.31	($0.03)	(0.1%)	$34.37	$36.29	$1.92	5.6%
2024	Sep	$30.63	$30.77	$0.14	0.4%	$29.32	$31.81	$2.48	8.5%
2024	Oct	$33.18	$33.26	$0.08	0.2%	$29.85	$31.87	$2.02	6.8%
2024	Nov	$29.78	$29.82	$0.04	0.1%	$25.70	$28.26	$2.55	9.9%
2024	Dec	$36.98	$37.05	$0.06	0.2%	$33.62	$34.98	$1.36	4.0%
2024	Jan - Sep	$33.78	$33.85	$0.07	0.2%	$31.73	$34.31	$2.58	8.1%
2024		$33.72	$33.79	$0.07	0.2%	$31.31	$33.74	$2.43	7.7%
2025	Jan	$67.53	$67.74	$0.21	0.3%	$59.93	$62.87	$2.94	4.9%
2025	Feb	$48.85	$49.02	$0.16	0.3%	$46.27	$48.90	$2.62	5.7%
2025	Mar	$40.76	$40.74	($0.03)	(0.1%)	$37.82	$42.11	$4.30	11.4%
2025	Apr	$44.36	$44.35	($0.01)	(0.0%)	$40.07	$45.42	$5.35	13.4%
2025	May	$37.56	$37.40	($0.16)	(0.4%)	$33.98	$36.34	$2.36	6.9%
2025	Jun	$53.01	$53.14	$0.13	0.2%	$62.53	$68.13	$5.60	9.0%
2025	Jul	$66.56	$66.76	$0.20	0.3%	$52.41	$59.38	$6.97	13.3%
2025	Aug	$39.24	$39.27	$0.03	0.1%	$35.97	$39.52	$3.55	9.9%
2025	Sep	$41.26	$41.24	($0.02)	(0.0%)	$40.49	$43.71	$3.22	7.9%
2025	Jan - Sep	$49.81	$49.88	$0.07	0.1%	$46.34	$50.51	$4.17	9.0%

Figure 3-25 shows the real-time daily average DLMP and PLMP in 2024 through September 2025.

Figure 3-25 Real-time daily average DLMP and PLMP: 2024 through September 2025



Fast start pricing created a larger difference between DLMP and PLMP in real time than in day ahead. Figure 3-26 shows the hourly difference between DLMP and PLMP in day-ahead and real-time for the first nine months of 2025.

The large differences between DA DLMP and PLMP on January 20, 2025, were caused by the higher transmission constraint penalty factors in the day-ahead dispatch run. In the dispatch run, the penalty factor was set at $30,000, while in the pricing run the penalty factor was set at $2,000.

The large differences between RT DLMP and PLMP on June 24, 2025, occurred when the energy component of the pricing run LMP was administratively set at $3,500 per MWh.

Figure 3-26 Hourly difference between DLMP and PLMP for day-ahead and real-time: January through September, 2025

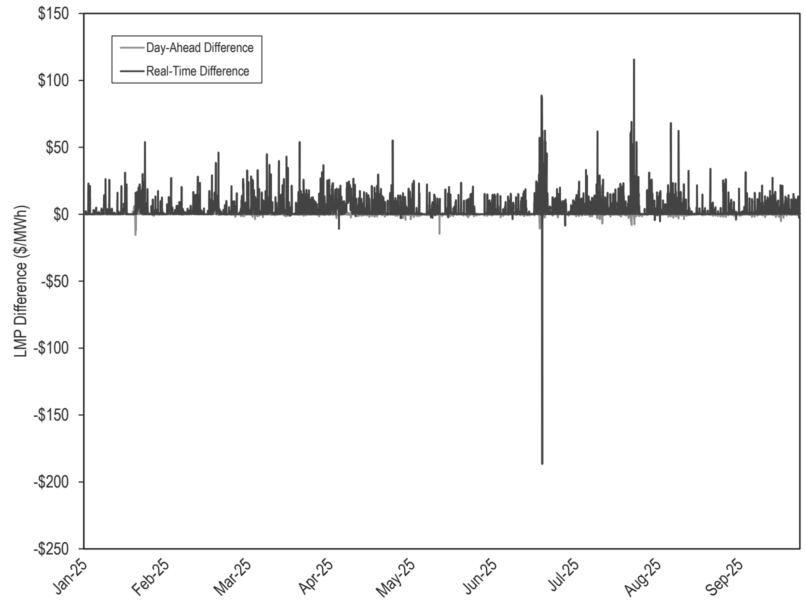


Figure 3-27 shows the hourly average load and LMP difference by hour of the day for the first nine months of 2025. The PLMP minus DLMP difference is largest at the times of the morning and evening peak loads.

Figure 3-27 Hourly average load and LMP difference: January through September, 2025

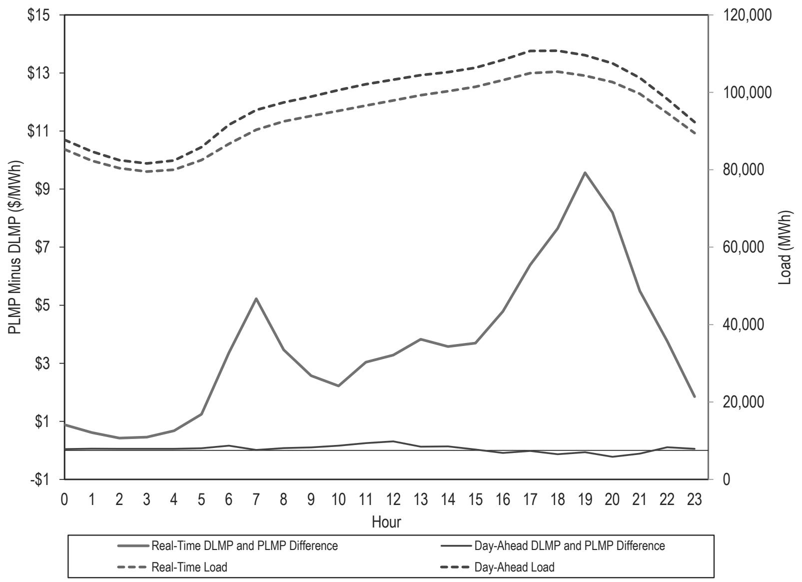


Table 3-32 shows the percent of total marginal units that are fast start units by unit type in 2024 and the first nine months of 2025. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

Table 3-32 Fast start units as a percent of real-time marginal units: 2024 through September 2025

		Dispatch Run				Pricing Run			
Year	Month	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2024	Jan	0.7%	0.6%	0.0%	1.3%	3.5%	1.1%	0.0%	4.7%
2024	Feb	0.4%	0.1%	0.1%	0.5%	2.2%	0.1%	0.1%	2.4%
2024	Mar	0.7%	0.2%	1.2%	2.1%	4.1%	0.8%	1.3%	6.2%
2024	Apr	1.5%	0.2%	0.2%	1.9%	6.5%	0.7%	0.1%	7.3%
2024	May	0.6%	0.2%	0.1%	1.0%	5.1%	0.6%	0.1%	5.8%
2024	Jun	0.5%	0.3%	0.1%	0.8%	3.5%	0.4%	0.1%	4.0%
2024	Jul	0.8%	0.5%	0.0%	1.4%	7.4%	1.0%	0.0%	8.5%
2024	Aug	0.6%	0.5%	0.0%	1.1%	5.0%	1.0%	0.0%	6.0%
2024	Sep	1.0%	0.1%	0.0%	1.1%	7.1%	0.4%	0.0%	7.6%
2024	Oct	1.2%	0.1%	0.0%	1.3%	6.4%	1.3%	0.0%	7.7%
2024	Nov	1.0%	0.2%	0.0%	1.4%	6.2%	0.6%	0.0%	7.0%
2024	Dec	0.5%	0.2%	0.0%	0.7%	2.2%	0.6%	0.0%	2.9%
2024	Jan - Sep	0.8%	0.3%	0.2%	1.3%	4.9%	0.7%	0.2%	5.8%
2025	Jan	0.8%	0.6%	0.1%	1.5%	4.5%	2.1%	0.1%	6.8%
2025	Feb	1.5%	0.1%	0.4%	2.0%	3.7%	0.6%	0.3%	4.6%
2025	Mar	0.5%	4.5%	0.1%	5.2%	3.4%	5.0%	0.1%	8.6%
2025	Apr	1.9%	1.8%	0.3%	4.1%	7.1%	2.2%	0.3%	9.7%
2025	May	0.6%	0.3%	0.0%	1.0%	3.9%	1.5%	0.0%	5.4%
2025	Jun	1.4%	0.2%	0.0%	1.6%	6.2%	0.8%	0.0%	7.0%
2025	Jul	2.6%	0.6%	0.0%	3.2%	11.2%	1.5%	0.0%	12.8%
2025	Aug	2.2%	0.5%	0.0%	2.7%	7.8%	1.1%	0.0%	8.9%
2025	Sep	1.2%	0.4%	0.0%	1.6%	5.7%	1.2%	0.0%	6.9%
2025	Jan - Sep	1.4%	1.0%	0.1%	2.6%	5.9%	1.8%	0.1%	7.9%

Table 3-33 shows the difference between day-ahead and real-time zonal average DLMP and PLMP for the first nine months of 2025.

Fast start pricing affects some zones more than others. The average increase in real-time prices in BGE was $4.53 per MWh, 8.9 percent, while the average increase in real-time prices in PECO was $2.83 per MWh, 7.8 percent.

Table 3-33 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): January through September, 2025

	2025 (Jan-Sep)							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$40.68	$40.75	$0.07	0.2%	$37.41	$40.34	$2.93	7.8%
AEP	$44.61	$44.65	$0.05	0.1%	$41.32	$45.00	$3.68	8.9%
APS	$45.47	$45.54	$0.06	0.1%	$42.28	$46.12	$3.84	9.1%
ATSI	$44.61	$44.62	$0.01	0.0%	$40.53	$44.17	$3.63	9.0%
BGE	$54.91	$55.00	$0.09	0.2%	$50.63	$55.16	$4.53	8.9%
COMED	$36.33	$36.40	$0.07	0.2%	$33.22	$36.27	$3.04	9.2%
DAY	$45.19	$45.24	$0.05	0.1%	$41.02	$44.72	$3.70	9.0%
DUKE	$43.78	$43.83	$0.05	0.1%	$39.66	$43.25	$3.60	9.1%
DOM	$57.36	$57.38	$0.02	0.0%	$54.33	$58.40	$4.08	7.5%
DPL	$44.19	$44.29	$0.10	0.2%	$39.61	$43.46	$3.85	9.7%
DUQ	$42.97	$43.01	$0.04	0.1%	$39.56	$43.13	$3.57	9.0%
EKPC	$43.42	$43.48	$0.06	0.1%	$40.30	$43.91	$3.61	9.0%
JCPLC	$40.86	$40.92	$0.07	0.2%	$37.61	$40.59	$2.97	7.9%
MEC	$43.25	$43.31	$0.06	0.1%	$39.39	$42.63	$3.24	8.2%
OVEC	$42.35	$42.39	$0.05	0.1%	$38.26	$41.75	$3.49	9.1%
PECO	$39.64	$39.71	$0.07	0.2%	$36.42	$39.25	$2.83	7.8%
PE	$46.90	$46.92	$0.03	0.1%	$42.87	$46.44	$3.57	8.3%
PEPCO	$54.04	$54.11	$0.07	0.1%	$49.94	$54.19	$4.26	8.5%
PPL	$39.12	$39.18	$0.07	0.2%	$35.81	$38.82	$3.01	8.4%
PSEG	$41.03	$41.11	$0.07	0.2%	$38.39	$41.43	$3.04	7.9%
REC	$44.75	$44.83	$0.07	0.2%	$41.80	$45.05	$3.25	7.8%

Table 3-34 shows the difference between day-ahead and real-time average DLMP and PLMP for PJM hubs for the first nine months of 2025.

The average increase in real-time prices for the DOMINION HUB was $3.94 per MWh, 8.6 percent, while the average increase in real-time prices for the NEW JERSEY HUB was $3.00 per MWh, 7.9 percent.

Table 3-34 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): January through September, 2025

	2025 (Jan-Sep)							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$42.22	$42.27	$0.05	0.1%	$38.16	$41.63	$3.48	9.1%
AEP-DAYTON HUB	$43.93	$43.99	$0.05	0.1%	$39.96	$43.56	$3.60	9.0%
ATSI GEN HUB	$43.86	$43.87	$0.00	0.0%	$39.67	$43.21	$3.54	8.9%
CHICAGO GEN HUB	$35.47	$35.54	$0.07	0.2%	$32.14	$35.20	$3.06	9.5%
CHICAGO HUB	$36.40	$36.47	$0.07	0.2%	$33.15	$36.18	$3.03	9.1%
DOMINION HUB	$48.52	$48.56	$0.04	0.1%	$45.66	$49.60	$3.94	8.6%
EASTERN HUB	$43.83	$43.92	$0.09	0.2%	$39.21	$42.96	$3.75	9.6%
N ILLINOIS HUB	$36.30	$36.37	$0.07	0.2%	$33.26	$36.30	$3.05	9.2%
NEW JERSEY HUB	$40.86	$40.93	$0.07	0.2%	$37.92	$40.91	$3.00	7.9%
OHIO HUB	$44.06	$44.12	$0.06	0.1%	$40.15	$43.76	$3.61	9.0%
WEST INT HUB	$45.64	$45.65	$0.02	0.0%	$42.10	$45.79	$3.69	8.8%
WESTERN HUB	$47.61	$47.67	$0.06	0.1%	$43.79	$47.62	$3.82	8.7%

Table 3-35 shows the frequency of the real-time pricing interval differences in DLMP and PLMP by price range for PJM zones for the first nine months of 2025.

Table 3-35 Frequency of real-time interval difference (dollars per MWh) between zonal DLMP and PLMP: January through September, 2025

	2025 (Jan-Sep)									
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	0.0%	1.0%	45.5%	42.0%	7.4%	3.4%	0.6%	0.1%	0.0%
AECO	0.0%	0.0%	5.2%	45.7%	40.1%	5.5%	2.7%	0.6%	0.1%	0.0%
AEP	0.0%	0.0%	1.4%	45.6%	41.1%	7.5%	3.6%	0.6%	0.1%	0.0%
APS	0.0%	0.0%	1.1%	45.6%	41.3%	7.4%	3.9%	0.7%	0.1%	0.0%
ATSI	0.0%	0.0%	1.4%	45.5%	41.4%	7.3%	3.5%	0.6%	0.1%	0.0%
BGE	0.0%	0.1%	2.5%	45.4%	37.9%	7.8%	4.8%	1.1%	0.3%	0.0%
COMED	0.2%	0.1%	5.4%	46.5%	37.8%	6.4%	2.9%	0.6%	0.1%	0.0%
DAY	0.0%	0.1%	1.6%	45.6%	40.8%	7.4%	3.6%	0.7%	0.1%	0.0%
DEOK	0.0%	0.1%	1.7%	45.7%	41.0%	7.3%	3.4%	0.6%	0.1%	0.0%
DOM	0.1%	0.3%	2.3%	45.5%	39.1%	7.4%	4.3%	1.0%	0.2%	0.0%
DPL	0.0%	0.2%	6.8%	45.6%	37.6%	5.3%	2.8%	1.0%	0.7%	0.0%
DUQ	0.0%	0.0%	1.5%	45.5%	41.6%	7.2%	3.4%	0.6%	0.1%	0.0%
EKPC	0.0%	0.0%	1.6%	45.6%	41.2%	7.4%	3.4%	0.6%	0.1%	0.0%
JCPL	0.0%	0.0%	3.5%	45.7%	41.7%	5.6%	2.8%	0.6%	0.1%	0.0%
METED	0.0%	0.2%	3.7%	45.5%	40.5%	6.2%	3.2%	0.6%	0.1%	0.0%
OVEC	0.0%	0.2%	1.8%	45.7%	41.1%	7.1%	3.3%	0.6%	0.1%	0.0%
PECO	0.0%	0.1%	6.2%	45.6%	39.3%	5.4%	2.7%	0.6%	0.1%	0.0%
PENELEC	0.0%	0.1%	2.0%	45.3%	41.0%	7.2%	3.6%	0.6%	0.1%	0.0%
PEPCO	0.0%	0.1%	2.4%	45.6%	38.5%	7.7%	4.5%	1.0%	0.2%	0.0%
PPL	0.0%	0.1%	3.8%	45.5%	41.4%	5.7%	2.9%	0.6%	0.1%	0.0%
PSEG	0.0%	0.0%	3.1%	45.7%	42.0%	5.7%	2.8%	0.6%	0.1%	0.0%
RECO	0.0%	0.1%	3.1%	45.4%	41.4%	6.2%	3.1%	0.6%	0.1%	0.0%

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[74]

PJM Real-Time Average LMP

Table 3-36 shows the real-time average LMP for the first nine months of 1998 through 2025.[75] The real-time average LMP in the first nine months of 2025 increased $14.57 per MWh, or 46.2 percent, from the first nine months of 2024, from $31.50 per MWh to $46.05 per MWh.

Table 3-36 Real-time average LMP (Dollars per MWh): January through September, 1998 through 2025

	Real-Time LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA	NA
1999	$31.65	$18.77	$83.28	$8.47	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	($5.77)	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	$10.12	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	($7.88)	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	$12.30	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	$3.43	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	$10.83	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	($2.90)	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	$5.55	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	$14.59	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	($34.51)	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	$8.70	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	($0.33)	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	($13.34)	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	$4.85	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	$15.42	41.3%	11.2%	224.8%
2015	$35.96	$27.88	$30.75	($16.76)	(31.8%)	(22.7%)	(58.5%)
2016	$27.43	$23.61	$15.73	($8.53)	(23.7%)	(15.3%)	(48.8%)
2017	$28.79	$25.28	$16.81	$1.36	5.0%	7.1%	6.9%
2018	$36.52	$27.26	$33.22	$7.73	26.8%	7.8%	97.6%
2019	$26.30	$23.39	$17.69	($10.22)	(28.0%)	(14.2%)	(46.8%)
2020	$19.95	$17.87	$10.48	($6.34)	(24.1%)	(23.6%)	(40.7%)
2021	$33.49	$26.82	$24.08	$13.54	67.9%	50.1%	129.8%
2022	$72.57	$59.66	$59.73	$39.08	116.7%	122.4%	148.0%
2023	$29.29	$25.56	$18.21	($43.28)	(59.6%)	(57.2%)	(69.5%)
2024	$31.50	$24.73	$26.35	$2.21	7.6%	(3.2%)	44.7%
2025	$46.07	$34.73	$53.62	$14.57	46.2%	40.5%	103.5%

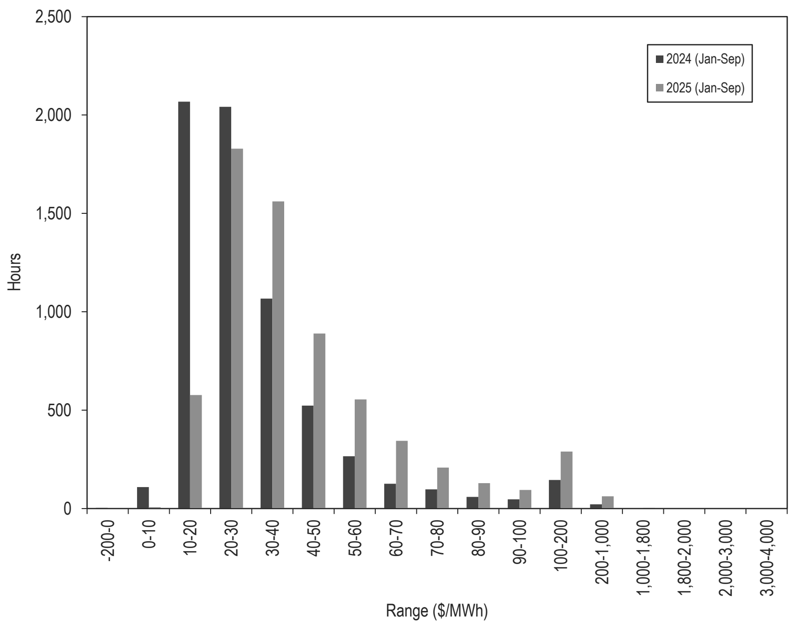
74 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

75 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

PJM Real-Time Average LMP Duration

Figure 3-28 shows the hourly distribution of the real-time average LMP in the first nine months of 2024 and 2025. In the first nine months of 2024, the most common price range was $10 to $20 per MWh. In the first nine months of 2025, the most common price range was $20 to $30 per MWh.

Figure 3-28 Distribution of real-time LMP: January through September, 2024 and 2025



Real-Time Load-Weighted Average LMP

Higher demand generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted average LMP reflects the average real-time LMP paid for actual MWh consumed during a year. Load-weighted average LMP is the average of PJM hourly LMP, with each hourly LMP weighted by the PJM total hourly load.

PJM Real-Time Load-Weighted Average LMP

Table 3-37 shows the real-time load-weighted average LMP for the first nine months of 1998 through 2025. The real-time load-weighted average LMP in the first nine months of 2025 increased $16.20 per MWh, or 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh.

Table 3-37 Real-time load-weighted average LMP (Dollars per MWh): January through September, 1998 through 2025

	Real-Time Load-Weighted Average LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA	NA
1999	$38.65	$20.02	$104.17	$12.59	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	($10.16)	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	$12.47	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	($9.01)	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	$11.61	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	$2.87	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	$14.01	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	($4.06)	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	$5.45	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	$15.43	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	($37.70)	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	$10.35	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	($0.44)	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	($14.46)	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	$4.72	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	$18.86	47.4%	12.8%	225.8%
2015	$38.94	$29.09	$33.95	($19.66)	(33.5%)	(23.3%)	(60.6%)
2016	$29.32	$24.60	$17.13	($9.62)	(24.7%)	(15.4%)	(49.6%)
2017	$30.36	$26.26	$18.81	$1.04	3.5%	6.7%	9.8%
2018	$39.43	$28.78	$36.82	$9.08	29.9%	9.6%	95.7%
2019	$27.60	$24.23	$18.69	($11.83)	(30.0%)	(15.8%)	(49.2%)
2020	$21.22	$18.66	$11.53	($6.38)	(23.1%)	(23.0%)	(38.3%)
2021	$35.68	$28.41	$26.03	$14.46	68.1%	52.3%	125.8%
2022	$77.84	$63.39	$68.59	$42.16	118.2%	123.1%	163.5%
2023	$30.87	$26.78	$19.67	($46.97)	(60.3%)	(57.8%)	(71.3%)
2024	$34.31	$26.40	$29.31	$3.44	11.1%	(1.4%)	49.0%
2025	$50.51	$37.12	$64.05	$16.20	47.2%	40.6%	118.5%

PJM Real-Time Monthly Load-Weighted Average LMP

Figure 3-29 shows the real-time monthly and yearly load-weighted average LMP for 1999 through September 2025.

Figure 3-29 Real-time monthly and yearly load-weighted average LMP: 1999 through September 2025

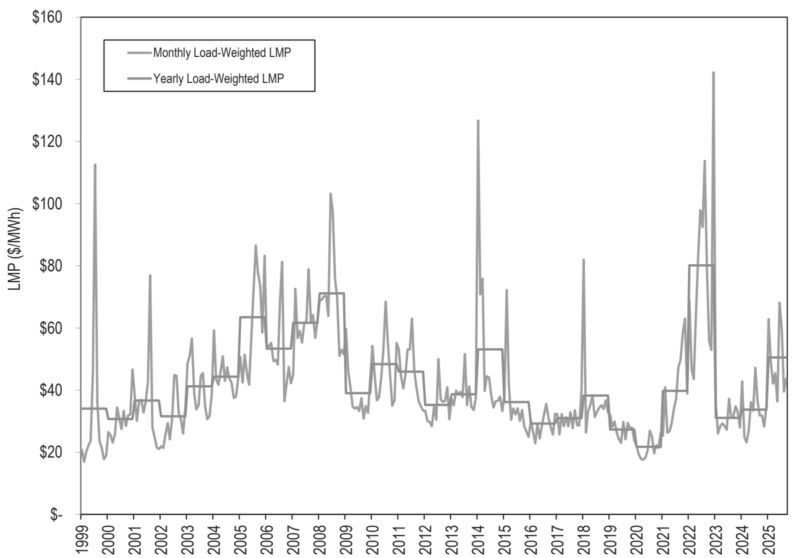


Table 3-38 shows the real-time monthly on peak and off peak load-weighted average LMP for 2024 through September 2025.

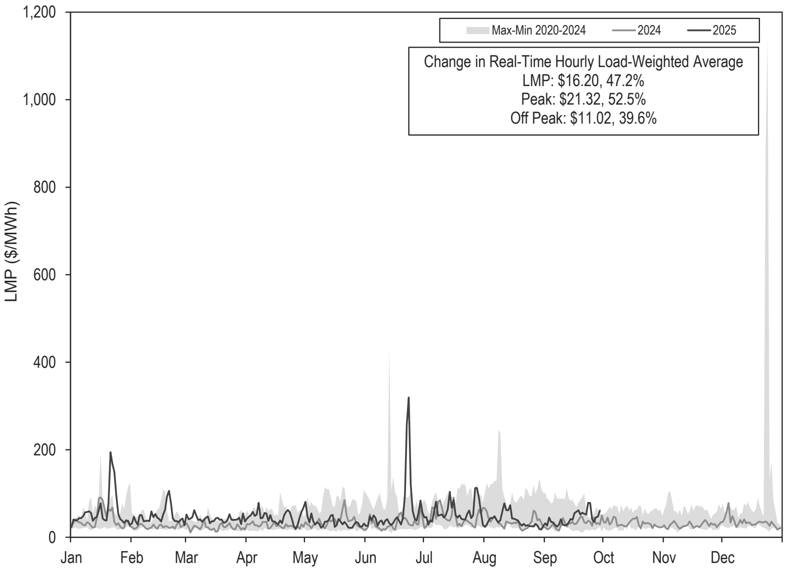
Table 3-38 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2024 through September 2025

	2024				2025			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$38.50	$47.10	$8.60	22.3%	$55.29	$70.54	$15.25	27.6%
Feb	$24.49	$25.23	$0.74	3.0%	$43.75	$54.12	$10.37	23.7%
Mar	$21.64	$24.79	$3.15	14.6%	$38.89	$45.68	$6.79	17.5%
Apr	$23.99	$30.03	$6.04	25.2%	$38.15	$52.08	$13.93	36.5%
May	$28.99	$42.74	$13.75	47.4%	$27.32	$45.53	$18.21	66.7%
Jun	$26.66	$40.04	$13.38	50.2%	$39.62	$94.51	$54.89	138.5%
Jul	$32.20	$60.78	$28.58	88.7%	$39.08	$77.77	$38.68	99.0%
Aug	$26.71	$44.99	$18.28	68.5%	$29.15	$49.92	$20.77	71.2%
Sep	$24.53	$39.42	$14.89	60.7%	$34.41	$52.55	$18.14	52.7%
Oct	$26.60	$36.49	$9.89	37.2%				
Nov	$23.80	$33.18	$9.38	39.4%				
Dec	$31.60	$38.70	$7.10	22.5%				

PJM Real-Time Daily Load-Weighted Average LMP

Figure 3-30 shows the real-time daily load-weighted average LMP for 2024 through September 2025.

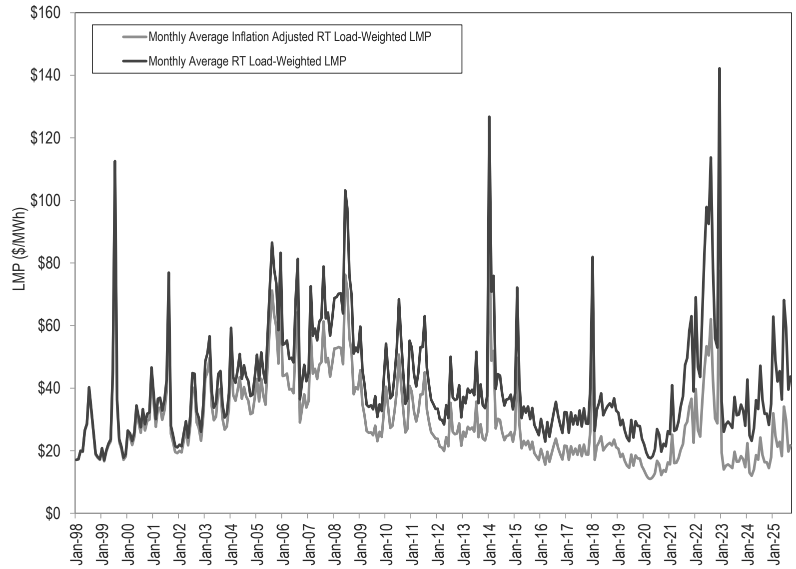
Figure 3-30 Real-time daily load-weighted average LMP: 2024 through September 2025



PJM Real-Time Monthly Inflation Adjusted Load-Weighted Average LMP

Figure 3-31 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through September 2025.[76] Table 3-39 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for every first nine months from 1998 through 2025.

Figure 3-31 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through September 2025



76 To obtain the inflation adjusted, monthly, load-weighted, average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 24, 2025)

Table 3-39 Real-time load-weighted and inflation adjusted load-weighted average LMP: January through September, 1998 through 2025

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Sep	Jan-Sep
1998	$26.06	$25.86
1999	$38.65	$37.55
2000	$28.49	$26.82
2001	$40.96	$37.39
2002	$31.95	$28.72
2003	$43.57	$38.33
2004	$46.44	$39.85
2005	$60.44	$50.09
2006	$56.39	$45.16
2007	$61.83	$48.36
2008	$77.27	$57.70
2009	$39.57	$29.93
2010	$49.91	$37.04
2011	$49.48	$35.59
2012	$35.02	$24.68
2013	$39.75	$27.58
2014	$58.60	$40.11
2015	$38.94	$26.60
2016	$29.32	$19.77
2017	$30.36	$20.05
2018	$39.43	$25.45
2019	$27.60	$17.49
2020	$21.22	$13.27
2021	$35.68	$21.39
2022	$77.84	$43.04
2023	$30.87	$16.41
2024	$34.31	$17.71
2025	$50.51	$25.40

Real-Time Dispatch and Pricing

On November 1, 2021, PJM implemented a new real-time dispatch process that aligned the timing of dispatch and pricing in the real-time energy market. The PJM Real-Time Energy Market is based on applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the real-time security constrained economic dispatch (RT SCED), the locational pricing calculator (LPC), and the ancillary services optimizer (ASO).[77] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

77 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 133 (Dec. 17, 2024).

Real-Time SCED and LPC

The LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast for a future point in time, called the target time. Prior to 2021, on average, PJM operators approved more than one RT SCED solution per five minute target time to send dispatch signals to resources. From January 2021 through September 2025, on average, PJM operators approved one RT SCED solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs every five minutes. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution, but LPC assigned the prices to a five minute interval that did not contain the target time of the RT SCED case it used. On November 1, 2021, PJM implemented changes to RT SCED that solved the energy dispatch case using a five-minute dispatch period, and ramped resources for five minutes to meet the load and reserve requirements at the end of each five minute period. The approved RT SCED solution that dispatched units for each five minute period was also used to calculate prices for the same five minute interval, aligning the prices with the dispatch signals.

Table 3-40 shows the number of RT SCED case solutions, the number of solutions that were approved, and the number and percent of approved solutions used in LPC. The RT SCED execution frequency is once every five minutes. PJM operators have the ability to execute additional RT SCED cases. Each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

Table 3-40 shows that in the first nine months of 2025, 97.8 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 97.2 percent in all of 2024.

Table 3-40 RT SCED cases solved, approved and used in pricing: January 2024 through September 2025

	2024				2025			
Month	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	45,594	9,161	8,891	97.1%	46,098	9,146	8,895	97.3%
Feb	43,066	8,659	8,288	95.7%	41,310	8,213	8,020	97.7%
Mar	45,340	8,972	8,845	98.6%	46,674	9,013	8,823	97.9%
Apr	44,365	8,767	8,606	98.2%	44,215	8,766	8,608	98.2%
May	46,149	9,177	8,853	96.5%	45,702	9,053	8,867	97.9%
Jun	44,464	8,841	8,598	97.3%	44,319	8,812	8,582	97.4%
Jul	45,629	9,138	8,881	97.2%	45,713	9,076	8,889	97.9%
Aug	45,616	9,192	8,894	96.8%	45,491	9,022	8,860	98.2%
Sep	44,275	8,752	8,550	97.7%	43,744	8,736	8,556	97.9%
Oct	45,806	9,144	8,879	97.1%				
Nov	44,055	8,850	8,607	97.3%				
Dec	45,460	9,120	8,899	97.6%				
Total	539,819	107,773	104,791	97.2%	403,266	79,837	78,100	97.8%

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 1700 (EPT) of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 1700 (EPT) of the second business day following the operating day.[78] Table 3-41 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2024 and the first nine months of 2025. In the first nine months of 2025, PJM recalculated LMPs for 1,926 five minute intervals or 2.45 percent of the total 78,612 five minute intervals.

78 OA Attachment K Section 1 § 1.10.8(e).

Table 3-41 Number of five minute interval real-time prices recalculated: January 2024 through September 2025

	2024			2025		
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Percent	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Percent
January	8,928	164	1.8%	8,928	154	1.7%
February	8,352	285	3.4%	8,064	189	2.3%
March	8,916	304	3.4%	8,916	680	7.6%
April	8,640	154	1.8%	8,640	126	1.5%
May	8,928	193	2.2%	8,928	153	1.7%
June	8,640	167	1.9%	8,640	162	1.9%
July	8,928	274	3.1%	8,928	183	2.0%
August	8,928	171	1.9%	8,928	137	1.5%
September	8,640	167	1.9%	8,640	142	1.6%
October	8,928	155	1.7%	-	-	
November	8,652	160	1.8%	-	-	
December	8,928	165	1.8%	-	-	
Total	105,408	2,359	2.2%	78,612	1,926	2.5%

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[79]

PJM Day-Ahead Average LMP

Table 3-42 shows the day-ahead average LMP for the first nine months of 2001 through 2025. The day-ahead average LMP for the first nine months of 2025 increased $14.60 per MWh, or 47.0 percent from the first nine months of 2024, from $31.09 per MWh to $45.69 per MWh.

Table 3-42 Day-ahead average LMP (Dollars per MWh): January through September, 2001 to 2025

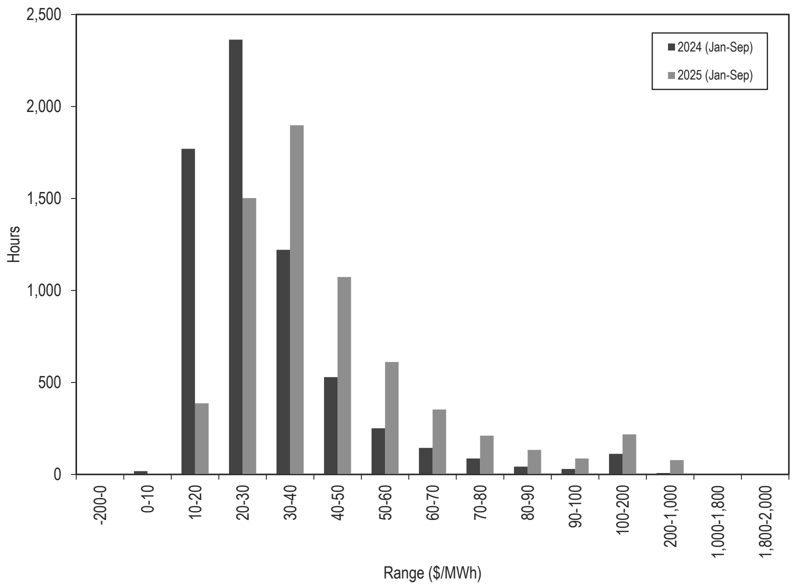
	Day-Ahead LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA	NA
2002	$28.29	$22.54	$19.09	($7.78)	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	$12.91	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	$1.44	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	$11.85	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	($4.03)	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	$3.79	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	$17.19	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	($34.08)	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	$8.46	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	($0.67)	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	($12.98)	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	$5.34	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	$16.26	43.4%	15.0%	247.8%
2015	$36.67	$30.56	$25.21	($17.09)	(31.8%)	(23.4%)	(57.3%)
2016	$27.90	$25.23	$11.37	($8.76)	(23.9%)	(17.4%)	(54.9%)
2017	$28.90	$26.60	$10.73	$0.99	3.6%	5.4%	(5.6%)
2018	$36.04	$29.75	$25.12	$7.14	24.7%	11.8%	134.2%
2019	$26.41	$24.76	$9.58	($9.63)	(26.7%)	(16.8%)	(61.9%)
2020	$19.72	$18.47	$6.99	($6.69)	(25.3%)	(25.4%)	(27.0%)
2021	$33.34	$28.28	$16.54	$13.63	69.1%	53.1%	136.7%
2022	$72.36	$63.56	$33.81	$39.02	117.0%	124.8%	104.4%
2023	$30.10	$27.83	$15.28	($42.26)	(58.4%)	(56.2%)	(54.8%)
2024	$31.09	$25.71	$21.00	$0.99	3.3%	(7.6%)	37.5%
2025	$45.69	$36.75	$35.12	$14.60	47.0%	42.9%	67.2%

79 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for a detailed definition of day-ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of the day-ahead average LMP for the first nine months of 2024 and 2025.

Figure 3-32 Distribution of day-ahead LMP: January through September, 2024 and 2025



Day-Ahead Load-Weighted Average LMP

Day-ahead load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead load-weighted LMP is the average of PJM day-ahead hourly LMP, each hourly LMP weighted by the PJM total cleared day-ahead, hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up to congestion.

PJM Day-Ahead Load-Weighted Average LMP

Table 3-43 shows the day-ahead load-weighted average LMP for the first nine months of 2001 through 2025. The day-ahead load-weighted average LMP for the first nine months of 2025 increased $16.03 or 47.4 percent from the first nine months of 2024, from $33.85 per MWh to $49.88 per MWh.

Table 3-43 Day-ahead load-weighted average LMP (Dollars per MWh): January through September, 2001 to 2025

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA	NA
2002	$32.29	$25.22	$22.81	($7.59)	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	$11.82	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	$0.49	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	$14.92	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	($5.32)	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	$3.59	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	$18.18	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	($36.61)	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	$9.77	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	($0.78)	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	($14.05)	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	$5.20	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	$19.60	49.6%	17.0%	238.0%
2015	$39.51	$32.15	$28.05	($19.58)	(33.1%)	(23.6%)	(58.3%)
2016	$29.69	$26.60	$12.38	($9.82)	(24.8%)	(17.3%)	(55.8%)
2017	$30.26	$27.95	$11.59	$0.56	1.9%	5.1%	(6.4%)
2018	$38.71	$31.62	$27.75	$8.45	27.9%	13.1%	139.5%
2019	$27.70	$25.85	$10.40	($11.01)	(28.4%)	(18.3%)	(62.5%)
2020	$20.95	$19.23	$7.75	($6.75)	(24.4%)	(25.6%)	(25.4%)
2021	$35.51	$30.01	$17.97	$14.57	69.5%	56.0%	131.8%
2022	$76.97	$67.42	$36.82	$41.46	116.7%	124.7%	104.9%
2023	$31.90	$29.08	$17.68	($45.07)	(58.6%)	(56.9%)	(52.0%)
2024	$33.85	$27.47	$23.62	$1.95	6.1%	(5.5%)	33.6%
2025	$49.88	$39.06	$40.28	$16.03	47.4%	42.2%	70.5%

PJM Day-Ahead Monthly Load-Weighted Average LMP

Figure 3-33 shows the day-ahead monthly and yearly load-weighted average LMP in 2001 through September 2025.

Figure 3-33 Day-ahead monthly and yearly load-weighted average LMP: 2001 through September 2025

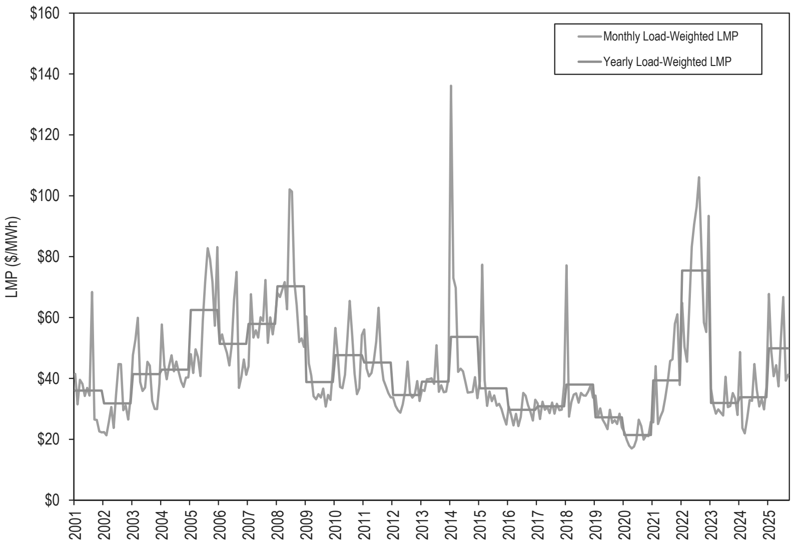
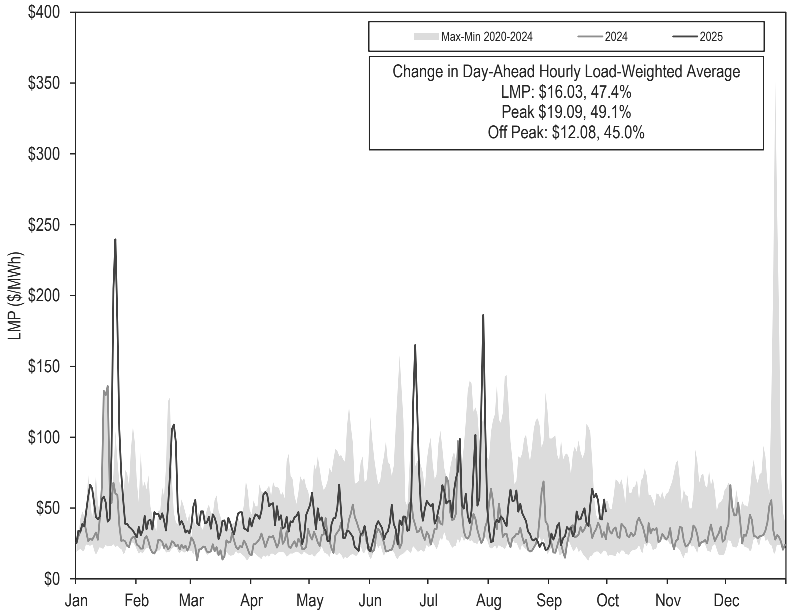


Figure 3-34 shows the day-ahead daily load-weighted average LMP in 2024 through September 2025 compared to the historic five year price range.

Figure 3-34 Day-ahead daily load-weighted average LMP: 2024 through September 2025



PJM Day-Ahead Monthly Inflation Adjusted Load-Weighted Average LMP

Figure 3-35 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through September 2025.[80] Table 3-44 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for every first nine months from 2000 through 2025.

Figure 3-35 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through September 2025

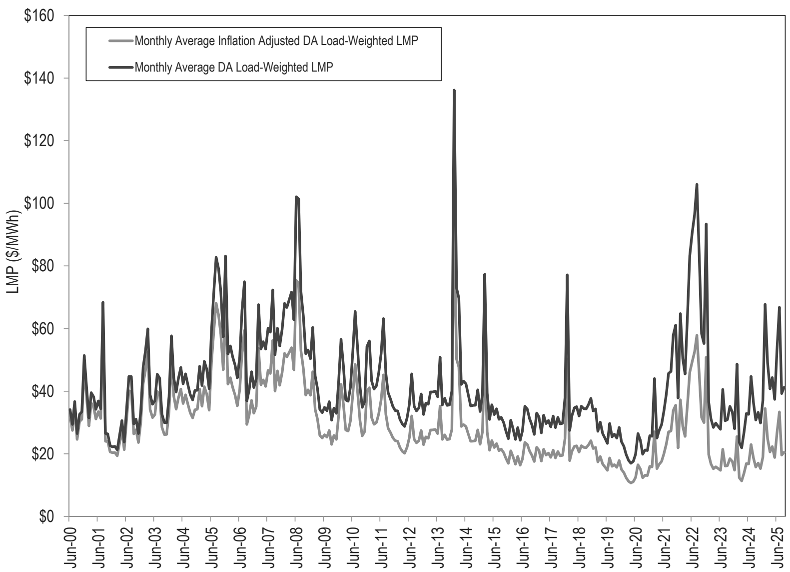


Table 3-44 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: January through September, 2001 through 2025

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Sep	Jan-Sep
2000	$31.81	$29.74
2001	$39.88	$36.41
2002	$32.29	$29.02
2003	$44.11	$38.81
2004	$44.59	$38.26
2005	$59.51	$49.32
2006	$54.19	$43.40
2007	$57.79	$45.19
2008	$75.96	$56.73
2009	$39.35	$29.77
2010	$49.12	$36.46
2011	$48.34	$34.79
2012	$34.29	$24.17
2013	$39.49	$27.40
2014	$59.09	$40.45
2015	$39.51	$26.99
2016	$29.69	$20.03
2017	$30.26	$19.99
2018	$38.71	$24.98
2019	$27.70	$17.55
2020	$20.95	$13.09
2021	$35.51	$21.30
2022	$76.97	$42.57
2023	$31.90	$16.96
2024	$33.85	$17.48
2025	$49.88	$25.09

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the day-ahead and real-time energy markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome.

80 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October24, 2025).

In practice, virtuals can receive a positive profit whenever there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets that is greater than uplift and administrative charges.

Virtual trading can only result in price convergence at a given location and market hour if the factors affecting prices at that location and hour, such as modeled contingencies, transmission constraint limits and sources of flows, are the same in both the day-ahead and real-time models.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may result in positive profits for the virtual but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions and without improving the efficiency of the energy market. This is termed false arbitrage.

The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market. Price convergence does not necessarily mean a zero or even a very small difference in prices between day-ahead and real-time energy markets. There may be factors, from uplift charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences.

INCs, DECs and UTCs allow participants to benefit from price differences between the day-ahead and real-time energy market. In theory, virtual transactions receive positive profits, after uplift and administrative charges, when they contribute to price convergence, but with false arbitrage, profits result with little or no price convergence. The seller of an INC must buy energy in the real-time energy market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, after uplift and administrative charges, the INC is profitable. The buyer of a DEC must sell energy in the real-time energy market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, after uplift and administrative charges, the DEC is profitable.

The profit of a UTC transaction is the net of the separate revenues of the component INC and DEC, after uplift and administrative charges. A UTC can be profitable if the profits on one side of the UTC transaction exceed the losses on the other side.

Virtual transactions, including UTCs since November 1, 2020, are required to pay uplift charges. Cleared INCs and DECs pay deviation charges based on the daily RTO and applicable regional operating reserve charge rates. DECs pay day-ahead operating reserve charges in addition to deviation charges. Cleared UTCs are treated, for uplift purposes, like DECs at the UTC sink point, and pay the regional and RTO deviation rates in addition to the day-ahead rate. Uplift charges for deviations may not apply if the virtual transaction is partially or fully offset by a corresponding real-time physical transaction at the same location.

In the day-ahead market, load bids are submitted by market buyers at aggregate pnodes, and PJM uses historic bus level load data to distribute the aggregate bids among the bus level pnodes that comprise the aggregate pnode. Effective December 14, 2023, PJM modified the method used to assign load bids to nodes from a single snapshot at 8:00 AM the week prior to the hourly demand data from one week prior to the Operating Day for each hour.[81]

Profitability of Virtual Transactions

The profit of a virtual transaction equals its net day-ahead and real-time energy market revenues minus uplift and administrative charges.

Table 3-45 shows, for cleared UTCs, the number of UTCs, the number of profitable UTCs, and the number of UTCs profitable at their source point, at their sink point, and at both source and sink points in the first nine months of 2024 and 2025. In the first nine months of 2025, 40.5 percent of all cleared

81 PJM Interconnection, L.L.C., Tariff Revisions to Improve the Determination of Day-Ahead Zonal Load Factors, Docket No. ER23-1529 (March 31, 2023).

UTC transactions were profitable. Of cleared UTC transactions, 62.7 percent were profitable on the source side and 35.1 percent were profitable on the sink side, but only 8.0 percent were profitable on both the source and sink side.

Table 3-45 Cleared UTCs with positive profits at source and sink points: January through September, 2024 and 2025[82]

(Jan-Sep)	Number of Cleared UTCs	Number of Profitable UTCs	Profitable at Source	Profitable at Sink	Profitable at Source and Sink	Share Profitable Overall	Share Profitable Source	Share Profitable Sink	Shar Sour
2024	4,486,499	1,780,160	2,732,000	1,674,097	345,697	39.7%	60.9%	37.3%	
2025	4,857,966	1,965,649	3,047,662	1,707,480	388,714	40.5%	62.7%	35.1%	

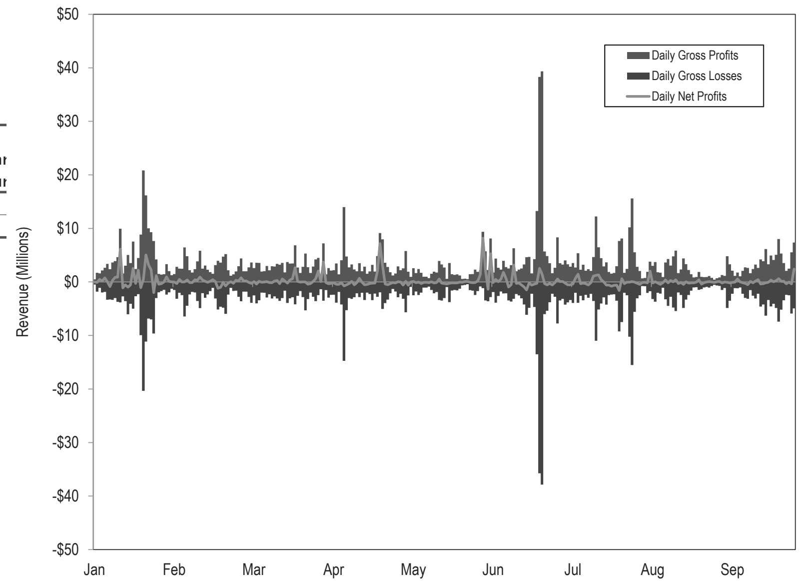
Table 3-46 shows the number of cleared INC and DEC transactions and the number of profitable transactions in the first nine months of 2024 and 2025. Of cleared INC and DEC transactions in the first nine months of 2025, 51.7 percent of INCs were profitable and 30.9 percent of DECs were profitable.

Table 3-46 Cleared INC and DEC transactions with positive profits: January through September, 2024 and 2025

(Jan-Sep)	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2024	2,794,484	1,422,401	50.9%	2,505,187	794,620	31.7%
2025	3,480,378	1,798,995	51.7%	3,253,797	1,006,376	30.9%

Figure 3-36 shows the positive, negative, and net daily profits for UTCs in the first nine months of 2025.

Figure 3-36 Positive, negative, and net daily UTC profits: January through September, 2025



82 Calculations exclude PJM administrative charges.

Figure 3-37 shows the cumulative UTC daily total net profits for each year from 2013 through September 2025.[83] Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs.

Figure 3-37 Cumulative daily UTC profits: January 2013 through September 2025

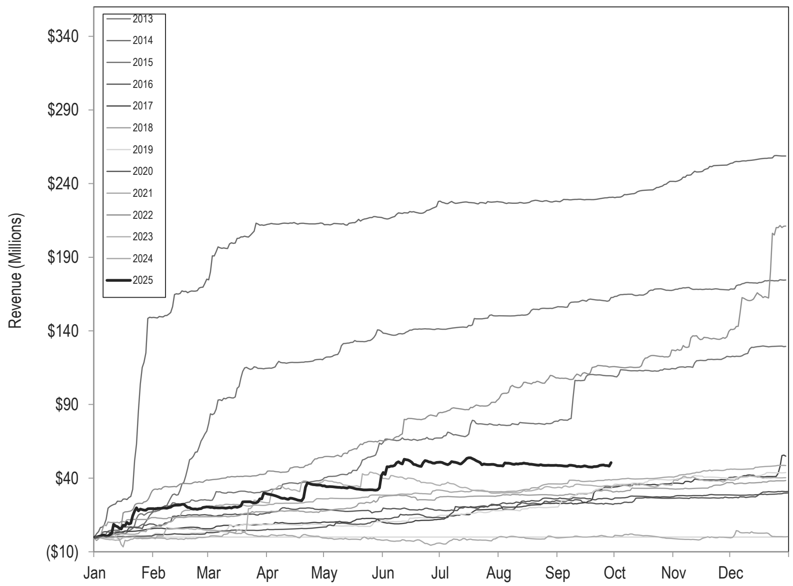


Table 3-47 shows UTC monthly total net profits for January 2013 through September 2025. Administrative charges are included for all months and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs. UTC profits were $211 million in 2022, higher than any year since 2014, with the largest monthly total in December 2022 at $75 million. In 2023, the most profitable UTC transactions were concentrated in the Dominion Zone and on dates with high real-time congestion in the Dominion Zone, which occurred primarily in January through May, 2023. The year 2024 was the least profitable year ever for UTC transactions, with very large profitable days occurring with less frequency than prior years. DOMINION HUB to DOM_RESID_AGG UTC remains the path with the highest cleared volume in the first nine months of 2025, June 2025 was the most profitable summer month for UTCs since August 2022.

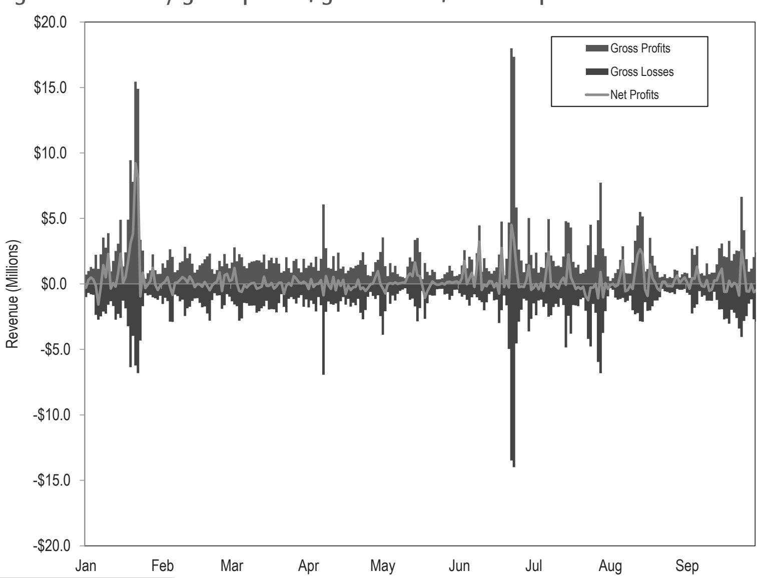
83 UTCs paid uplift only after October 31, 2020.

Table 3-47 UTC profits by month: January 2013 through September 2025

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429	$8,573,276	$3,957,296	($141,240)	$1,628,186	$1,170,367	$2,319,727	$30,887,320
2021	$6,421,567	$13,241,294	$1,788,961	$4,529,921	$2,542,898	$3,384,291	($1,199,849)	$5,330,600	$2,649,331	$2,148,861	$5,091,590	$2,665,873	$48,595,339
2022	$30,954,077	$7,236,325	$4,411,627	$11,317,095	$11,658,586	$16,398,181	$9,481,970	$17,376,381	$6,783,480	$7,325,933	$13,116,641	$75,067,601	$211,127,897
2023	($374,877)	$5,180,921	$18,722,180	$13,543,116	$5,121,917	($6,820,656)	($5,587,077)	$3,667,565	$1,041,650	$787,185	$3,734,966	$1,259,381	$40,276,272
2024	($798,085)	$741,801	$505,530	($1,048,989)	($1,481,223)	($1,997,609)	$3,605,145	($28,816)	$440,898	($852,701)	$472,000	$677,521	$235,473
2025	$19,307,539	$965,550	$9,446,437	$5,569,957	($1,921,483)	$17,309,458	($1,634,565)	($406,499)	$1,936,052				$50,572,446

Figure 3-38 shows the positive, negative, and net daily profits for INCs and DECs in the first nine months of 2025. Differences in the modeling of transmission constraints between day ahead and real time, including the use of different constraint limits or a constraint being modeled in one market but not the other, remain a principal source of false arbitrage profits and a major reason for the overall profitability of virtual transactions.

Figure 3-38 Daily gross profits, gross losses, and net profits of all INC and DEC transactions: January through September, 2025[84]



84 Calculations exclude PJM administrative charges.

Figure 3-39 shows the positive, negative, and net daily profits for INCs in the first nine months of 2025.

Figure 3-39 Daily gross profits, gross losses, and net profits for INC transactions: January through September, 2025[85]

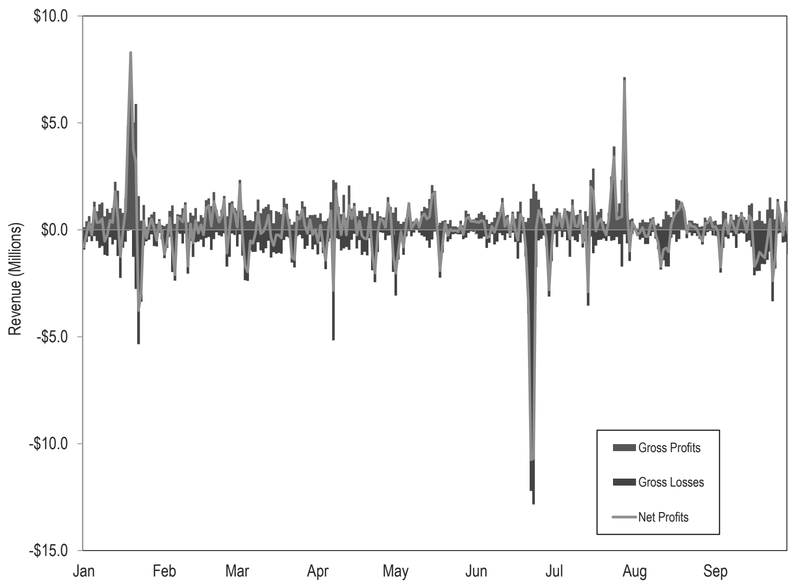
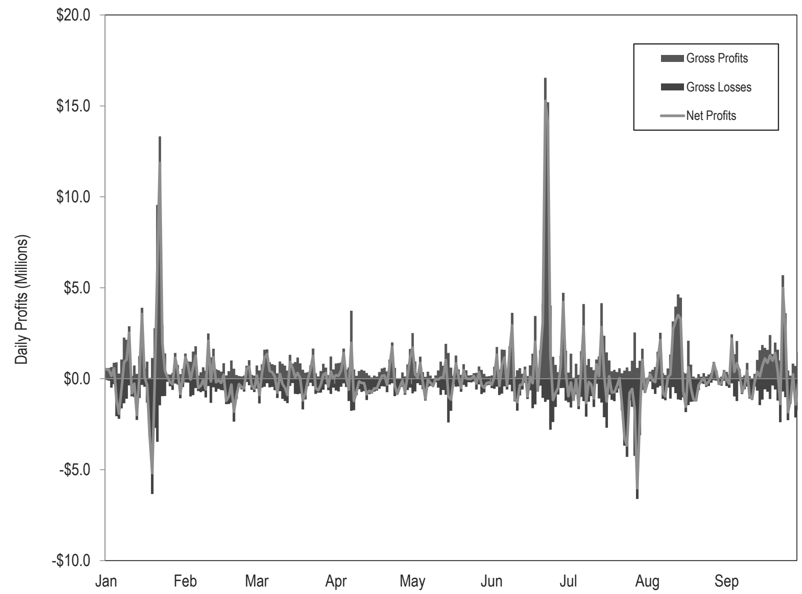


Figure 3-40 shows the positive, negative, and net daily profits for DECs in the first nine months of 2025.

Figure 3-40 Daily gross profits, gross losses, and net profits for DEC transactions: January through September, 2025



85 Calculations exclude PJM administrative charges.

Figure 3-41 shows the cumulative INC and DEC daily profits in the first nine months of 2025. Virtual trading can be profitable without contributing to price convergence because the addition of virtual supply or demand in the day-ahead market does not and cannot correct for factors not included in the day-ahead model, such as the use of different transmission constraint limits in day ahead versus real time.

Figure 3-41 Cumulative daily INC and DEC profit: January through September, 2025

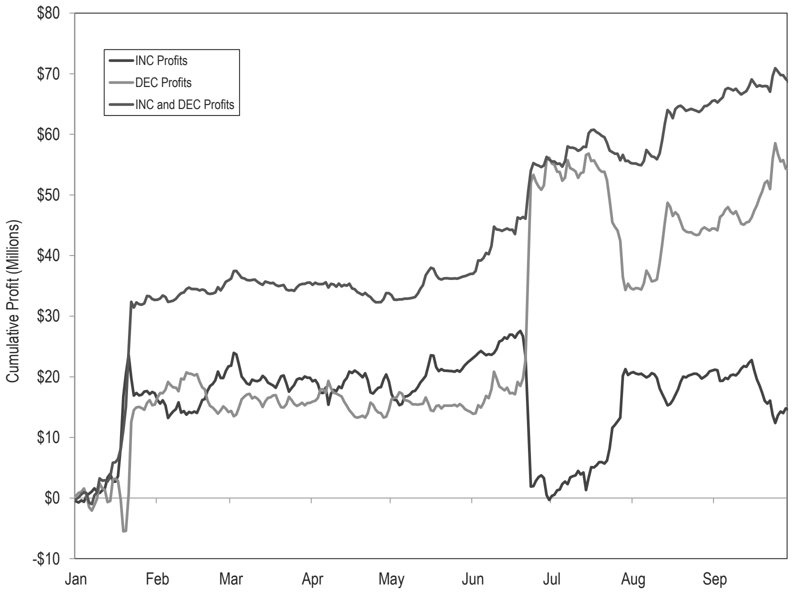


Table 3-48 shows INC and DEC profits by month in the first nine months of 2025.

Table 3-48 INC and DEC profits by month: January through September, 2025

Month	January	February	March	April	May	June	July	August	September	Total
INCs	$17,506,715	$3,444,425	($1,114,741)	$550,610	$1,968,221	($21,882,359)	$19,815,130	$611,357	($6,283,299)	$14,616,059
DECs	$15,315,025	($575,819)	$944,652	($2,254,255)	$990,626	$41,395,416	($20,450,397)	$8,744,220	$9,946,108	$54,055,576
INCs and DECs	$32,821,739	$2,868,606	($170,089)	($1,703,644)	$2,958,846	$19,513,057	($635,267)	$9,355,577	$3,662,809	$68,671,635

All virtual transactions are subject to uplift charges. Each cleared MWh of a virtual transaction pays uplift at the daily operating reserve charge rates, but UTCs pay uplift only at the transaction sink. Cleared increment offers pay the regional and RTO deviation rates, and cleared decrement bids pay the day-ahead rate in addition. Cleared up to congestion transactions pay the same rate as a decrement bid but only at the transaction's sink point, the day-ahead rate and RTO and regional deviation rates.

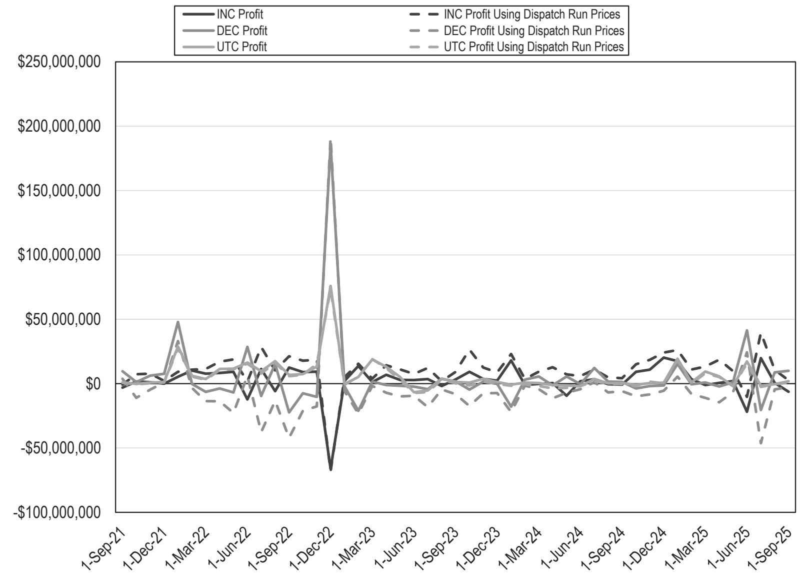
In the first nine months of 2025, INCs paid a total of $19.6 million, DECs paid a total of $24.1 million, and UTCs paid a total of $46.3 million in uplift. This compares to total INC profits of $14.6 million, total DEC profits of $54.1 million, and total UTC profits of $50.7 million.

Effect of Fast Start Pricing on Virtuals

The implementation of fast start pricing on September 1, 2021, has resulted in changes to the settlement of virtual transactions. Prior to fast start pricing, virtual products were cleared and settled based on a single set of prices. The dispatch and pricing run prices were the same. With fast start pricing, all virtual products are cleared using day-ahead dispatch run prices, but pay and receive the day-ahead and real-time pricing run prices. The use of fast start pricing has a direct effect on virtual settlements through the use of prices different from those used to dispatch virtuals. This means that a DEC may clear in the day-ahead market, based on the dispatch run, even though its offer is lower than the final, pricing run price. This means that an INC may clear even though its offer is higher than the day-ahead market price. The use of fast start pricing also results in divergence between day-ahead and real-time prices, which can be targeted by virtual traders. The fact that fast start pricing increases prices more in the real-time market, all else held equal, increases the profitability of DECs and decreases the profitability of INCs.

Figure 3-42 shows the total monthly profits received by INCs, DECs, and UTCs, compared to the profits they would have received if dispatch run prices had been used in settlement for each month since the initial implementation of fast start pricing in September 2021. Since its implementation, fast start pricing has consistently increased profits for DECs and decreased profits for INCs but has not significantly affected profits for UTCs. Fast start pricing creates a difference between day-ahead and real-time prices. Virtual traders can benefit from this difference without contributing to price convergence.

Figure 3-42 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through September 30, 2025



From the implementation of fast start pricing on September 1, 2021, through September 30, 2025, the cumulative difference in profit between the pricing run and the dispatch run for INCs was -$387.0 million, the cumulative difference in profit for DECs was $499.5 million, and the cumulative difference in profit for UTCs was $44.8 million. Fast start pricing led to a net increase of $157.3 million in cumulative profits for virtual transactions since September 1, 2021.

There are incentives to use virtual transactions to profit from price differences between the day-ahead and real-time energy markets, but there is no reason to believe that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets, about modeling differences and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the day-ahead energy market. Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis.

Day-ahead and Real-time Prices

Table 3-49 shows the difference between the day-ahead and the real-time average LMP in the first nine months of 2024 and 2025.

Table 3-49 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2024 and 2025[86]

	2024 (Jan-Sep)				2025 (Jan-Sep)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$31.09	$31.50	$0.41	1.3%	$45.69	$46.07	$0.38	0.8%
Median	$25.71	$24.73	($0.98)	(4.0%)	$36.75	$34.73	($2.02)	(5.8%)
Standard deviation	$21.00	$26.35	$5.35	20.3%	$35.12	$53.62	$18.49	34.5%
Peak average	$37.94	$37.89	($0.05)	(0.1%)	$56.19	$57.01	$0.81	1.4%
Peak median	$31.43	$29.87	($1.57)	(5.2%)	$44.51	$41.89	($2.62)	(6.3%)
Peak standard deviation	$24.51	$29.38	$4.87	16.6%	$43.36	$71.50	$28.14	39.4%
Off peak average	$25.09	$25.91	$0.82	3.2%	$36.51	$36.51	($0.00)	(0.0%)
Off peak median	$21.40	$20.60	($0.80)	(3.9%)	$31.64	$30.41	($1.23)	(4.1%)
Off peak standard deviation	$14.97	$21.89	$6.92	31.6%	$22.08	$26.90	$4.81	17.9%

86 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-50 shows the difference between the day-ahead and the real-time load-weighted LMP in the first nine months of 2001 through 2025.

Table 3-50 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2025

	Load-Weighted Average LMP					
Jan-Sep	Day-Ahead	Real-Time	Difference	Percent of Real-Time	Average Absolute Difference	Average Absolute Difference as a Percent of Real-Time
2001	$39.88	$40.96	$1.09	2.7%	$11.88	29.0%
2002	$32.29	$31.95	($0.33)	(1.0%)	$7.16	22.4%
2003	$44.11	$43.57	($0.54)	(1.2%)	$12.54	28.8%
2004	$44.59	$46.44	$1.84	4.0%	$9.92	21.4%
2005	$59.51	$60.44	$0.93	1.5%	$12.35	20.4%
2006	$54.19	$56.39	$2.19	3.9%	$12.02	21.3%
2007	$57.79	$61.83	$4.05	6.5%	$14.63	23.7%
2008	$75.96	$77.27	$1.30	1.7%	$17.70	22.9%
2009	$39.35	$39.57	$0.21	0.5%	$6.19	15.6%
2010	$49.12	$49.91	$0.79	1.6%	$9.82	19.7%
2011	$48.34	$49.48	$1.14	2.3%	$10.05	20.3%
2012	$34.29	$35.02	$0.73	2.1%	$6.33	18.1%
2013	$39.49	$39.75	$0.26	0.7%	$6.47	16.3%
2014	$59.09	$58.60	($0.49)	(0.8%)	$16.25	27.7%
2015	$39.51	$38.94	($0.57)	(1.5%)	$9.14	23.5%
2016	$29.69	$29.32	($0.37)	(1.3%)	$5.76	19.6%
2017	$30.26	$30.36	$0.10	0.3%	$4.17	13.7%
2018	$38.71	$39.43	$0.73	1.8%	$8.38	21.3%
2019	$27.70	$27.60	($0.10)	(0.4%)	$4.64	16.8%
2020	$20.95	$21.22	$0.28	1.3%	$3.52	16.6%
2021	$35.51	$35.68	$0.17	0.5%	$6.87	19.3%
2022	$76.97	$77.84	$0.87	1.1%	$13.91	17.9%
2023	$31.90	$30.87	($1.03)	(3.3%)	$6.95	22.5%
2024	$33.85	$34.31	$0.46	1.3%	$8.79	25.6%
2025	$49.88	$50.51	$0.63	1.2%	$13.15	26.0%

Table 3-51 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP in the first nine months of 2024 and 2025.

Table 3-51 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through September, 2024 and 2025

	2024 Jan - Sep		2025 Jan - Sep	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	0	0.0%	6	0.1%
($200) to ($100)	5	0.1%	31	0.6%
($100) to ($50)	48	0.8%	72	1.7%
($50) to $0	3,991	61.5%	3,988	62.5%
$0 to $50	2,419	98.3%	2,295	97.6%
$50 to $100	81	99.5%	108	99.2%
$100 to $200	24	99.9%	35	99.8%
$200 to $400	6	100.0%	8	99.9%
$400 to $800	1	100.0%	4	99.9%
>= $800	0	100.0%	4	100.0%

Figure 3-43 shows the differences between day-ahead and real-time hourly average LMP in the first nine months of 2025.

The largest difference was $1,436.65 per MWh on June 24, 2025.

Figure 3-43 Real-time hourly average LMP minus day-ahead hourly average LMP: January through September, 2025

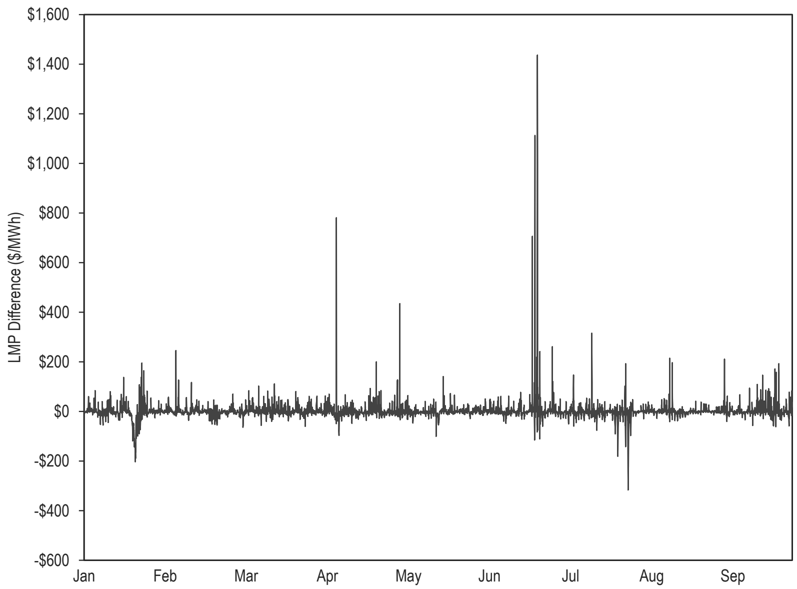
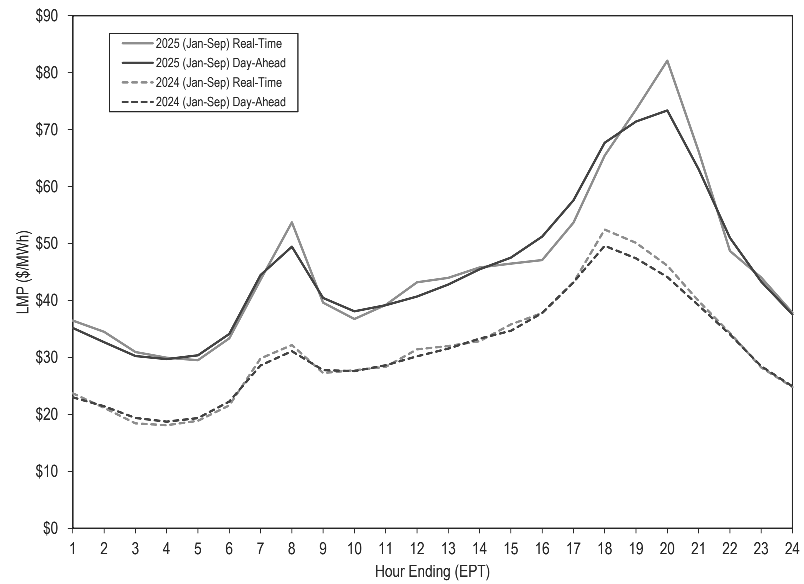


Figure 3-44 shows day-ahead and real-time load-weighted average LMP by hour of the day in the first nine months of 2024 and 2025.

Figure 3-44 System hourly average LMP: January through September, 2024 and 2025



Zonal LMP and Dispatch

Table 3-52 shows real-time zonal average and load-weighted average LMP for the first nine months of 2024 and 2025.

Table 3-52 Real-time zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2024 and 2025

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
	2024	2025	Percent	2024	2025	Percent
Zone	Jan-Sep	Jan-Sep	Change	Jan-Sep	Jan-Sep	Change
ACEC	$27.34	$40.34	47.5%	$31.01	$47.19	52.2%
AEP	$31.29	$45.00	43.8%	$33.43	$48.10	43.9%
APS	$31.98	$46.12	44.2%	$34.63	$50.50	45.8%
ATSI	$31.41	$44.17	40.6%	$33.78	$47.53	40.7%
BGE	$40.58	$55.16	35.9%	$46.83	$62.73	33.9%
COMED	$26.14	$36.27	38.8%	$29.08	$40.72	40.0%
DAY	$32.62	$44.72	37.1%	$35.47	$48.47	36.7%
DUKE	$31.16	$43.25	38.8%	$33.74	$46.80	38.7%
DOM	$36.51	$58.40	60.0%	$39.78	$64.13	61.2%
DPL	$31.02	$43.46	40.1%	$36.68	$51.57	40.6%
DUQ	$31.35	$43.13	37.6%	$33.98	$46.64	37.3%
EKPC	$30.85	$43.91	42.4%	$33.86	$48.65	43.7%
JCPLC	$27.43	$40.59	48.0%	$31.14	$47.59	52.8%
MEC	$28.17	$42.63	51.3%	$30.84	$47.58	54.3%
OVEC	$29.64	$41.75	40.8%	$29.82	$42.31	41.9%
PECO	$27.01	$39.25	45.3%	$30.31	$44.43	46.6%
PE	$31.27	$46.44	48.5%	$33.09	$49.94	50.9%
PEPCO	$37.85	$54.19	43.2%	$42.92	$61.79	44.0%
PPL	$26.57	$38.82	46.1%	$28.86	$43.21	49.7%
PSEG	$27.77	$41.43	49.2%	$30.54	$46.85	53.4%
REC	$29.56	$45.05	52.4%	$32.80	$51.59	57.3%
PJM	$31.50	$46.07	46.2%	$34.31	$50.51	47.2%

Table 3-53 shows day-ahead zonal average and load-weighted average LMP for the first nine months of 2024 and 2025.

Table 3-53 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2024 and 2025

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
	2024	2025	Percent	2024	2025	Percent
Zone	Jan-Sep	Jan-Sep	Change	Jan-Sep	Jan-Sep	Change
ACEC	$27.01	$40.75	50.9%	$30.36	$46.30	52.5%
AEP	$30.60	$44.65	45.9%	$32.81	$47.73	45.5%
APS	$31.78	$45.54	43.3%	$34.29	$49.21	43.5%
ATSI	$30.90	$44.62	44.4%	$33.15	$47.71	43.9%
BGE	$40.32	$55.00	36.4%	$46.10	$62.03	34.5%
COMED	$25.88	$36.40	40.7%	$28.37	$40.47	42.6%
DAY	$32.07	$45.24	41.1%	$34.91	$48.87	40.0%
DUKE	$30.83	$43.83	42.2%	$33.48	$47.35	41.4%
DOM	$36.72	$57.38	56.3%	$40.21	$63.63	58.3%
DPL	$30.96	$44.29	43.1%	$37.04	$52.37	41.4%
DUQ	$30.54	$43.01	40.9%	$33.22	$46.24	39.2%
EKPC	$30.08	$43.48	44.5%	$33.24	$48.68	46.4%
JCPLC	$26.94	$40.92	51.9%	$29.95	$46.19	54.2%
MEC	$28.46	$43.31	52.1%	$31.03	$47.77	54.0%
OVEC	$29.23	$42.39	45.0%	$28.68	$41.61	45.1%
PECO	$26.72	$39.71	48.6%	$29.71	$44.14	48.6%
PE	$31.37	$46.92	49.6%	$33.26	$50.04	50.5%
PEPCO	$37.97	$54.11	42.5%	$43.54	$61.38	41.0%
PPL	$26.60	$39.18	47.3%	$28.74	$43.21	50.3%
PSEG	$27.16	$41.11	51.3%	$29.66	$45.31	52.8%
REC	$29.16	$44.83	53.7%	$31.96	$49.44	54.7%
PJM	$31.09	$45.69	47.0%	$33.85	$49.88	47.4%

Figure 3-45 is a map of the real-time load-weighted average LMP in the first nine months of 2025. In the legend, green represents the real-time load-weighted average LMP in the first nine months of 2025 and each increment to the right represents five percent of the pricing nodes above the real-time load-weighted average LMP in the first nine months of 2025 and each increment to the left represents 25 percent of the pricing nodes below the real-time load-weighted average LMP in the first nine months of 2025.

Figure 3-45 Real-time load-weighted average LMP: January through September, 2025

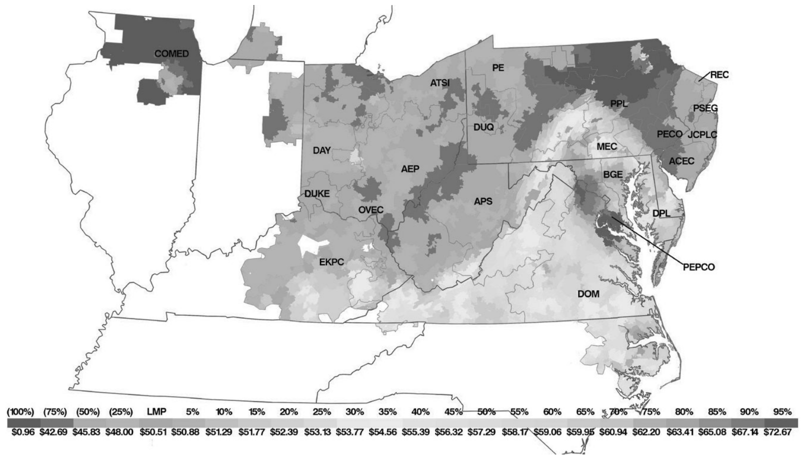
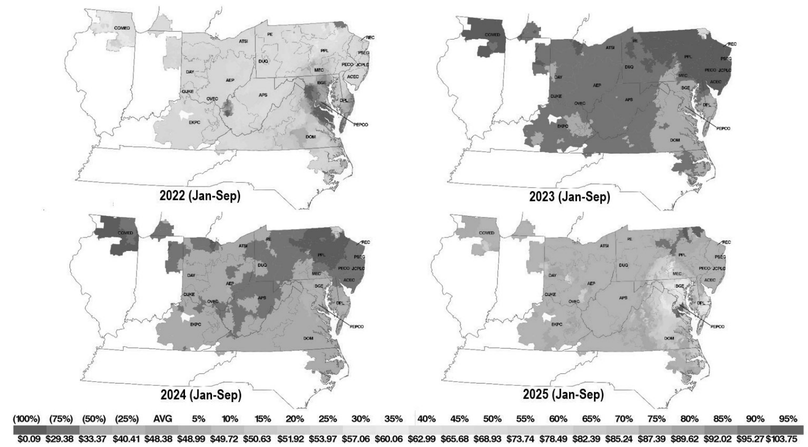


Figure 3-46 includes maps of the real-time load-weighted average LMP in the first nine months of 2022 through 2025. In the legend, green represents the average price in the first nine months of 2022 through 2025 and each block to the right represents five percent of the pricing nodes above the average price in the first nine months of 2022 through 2025 and each block to the left represents 25 percent of the pricing nodes below the average price in the first nine months of 2022 through 2025.

Figure 3-46 Real-time load-weighted average LMP map: January through September, 2022 through 2025



Transmission Constraint Penalty Factors (TCPF)

LMPs are generally set by the offer prices of marginal resources. When a transmission constraint is binding, the flow on the constraint is equal to its limit and the shadow price of the constraint is a function of offer prices of marginal resources. LMP may, at times, be set by transmission constraint penalty factors. When a transmission constraint is limiting and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing, but only when properly applied. The TCPFs are applied incorrectly about 94 percent of the time. In addition, it is not clear that the line ratings are correctly defined, by duration of the flow and ambient conditions, by the transmission owners who have sole control over the line ratings with no meaningful oversight.

PJM operators routinely reduce the control limits on transmission constraint line ratings used in the market clearing software (SCED) by setting the control limits to 95 percent of the actual line ratings.[87] The result is that transmission constraint penalty factors set price much more frequently than needed or appropriate. PJM reduces the control limits both to control for actual flows and for flows that would only result from a contingency (N-1).

Since the implementation of fast start pricing on September 1, 2021, PJM set the default level of the transmission constraint penalty factor in the pricing run of the day-ahead market at $2,000 per MWh. The default level of the transmission constraint penalty factor in the dispatch run of the day-ahead market was left unchanged at $30,000 per MWh.

Table 3-54 shows the frequency and average shadow price of transmission constraints in the PJM real-time market. In the first nine months of 2025, there were 158,826 transmission constraint five minute intervals in the real-time market with a nonzero shadow price. For 18,497, or 11.6 percent, of these transmission constraint intervals, the control limit was violated, meaning that the flow exceeded the facility limit used in SCED.[88] The data on violations includes both violations that result from reductions in the SCED control limit by PJM and violations that are based on the actual line ratings. Of the 18,497 constraint intervals, PJM used actual line limits for 2,773 or 1.7 percent of the constraint intervals. For the remaining 15,724 or 9.9 percent of the constraint intervals, PJM used reduced line limits. In those cases, the actual line limit was not violated. In all cases where violations resulted from reductions by PJM from actual line ratings the shadow prices and resulting LMPs were set by the violation penalty factors. In the first nine months of 2025, the average shadow price of transmission constraints ($1,995.20)) when the line limit used in SCED was violated with a reduced line limit was 6.4 times higher than when the transmission constraint was binding but not violated ($310.95) at its limit used in SCED.

87 Actual transmission line limits are set by the transmission owner. PJM chooses the control limits. At present the actual line rating methods are not reviewed by FERC, or PJM, or the MMU.

88 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

Market to Market Transmission Constraints are categorized separately because of the unique rules governing the congestion management of these constraints by PJM and MISO. In the real-time market, PJM and MISO initiate a joint congestion management process commonly referred as "market to market" if they recognize substantial flows originating from the other RTO on their constraints. The identified constraints are then modeled in the dispatch optimizations of the both RTOs. After every approved solution, the shadow prices are exchanged between the RTOs.

Table 3-54 Frequency and average shadow price of transmission constraints in the real-time market: January through September, 2024 and 2025

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)
Violated Transmission Constraints (Actual)	441	2,773	$677.59	$943.53
Violated Transmission Constraints (Reduced)	9,320	15,724	$1,979.52	$1,995.20
Binding Transmission Constraints	99,671	104,982	$215.40	$310.95
Market to Market Transmission Constraints	40,642	35,347	$264.81	$426.85
All Transmission Constraints	150,074	158,826	$339.69	$514.53

Table 3-55 shows the frequency and average shadow price of transmission constraints in the PJM day-ahead market. In the first nine months of 2025, there were 56,386 transmission constraint hours in the day-ahead market with a nonzero shadow price. For 145, or less than one percent, of these transmission constraint hours, the line limit was violated, meaning that the flow exceeded the facility limit used in the day-ahead pricing run solution.

Table 3-55 Frequency and average shadow price of transmission constraints in the day-ahead market: January through September, 2024 and 2025

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)
Violated Transmission Constraints (Actual)	31	145	$2,000.00	$2,000.00
Market to Market Transmission Constraints	52,558	48,900	$64.81	$103.01
Binding Transmission Constraints	4,880	7,341	$105.35	$145.23
All Transmission Constraints	57,469	56,386	$69.29	$113.39

Table 3-56 shows the frequency of violated transmission constraints by voltage level in the real-time market. In the first nine months of 2025, 76.4 percent of the violated transmission constraint intervals had a voltage level at or below 230 kV.

Table 3-56 Frequency of PJM violated transmission constraints in the real-time market by voltage: January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
1 kV	56	0.6%	269	1.5%
69 kV	702	7.2%	1,069	5.8%
115 kV	1,928	19.8%	5,794	31.3%
138 kV	2,772	28.4%	3,422	18.5%
161 kV	16	0.2%	-	0.0%
230 kV	2,536	26.0%	3,585	19.4%
345 kV	618	6.3%	486	2.6%
500 kV	911	9.3%	3,825	20.7%
765 kV	222	2.3%	47	0.3%
Total	9,761	100.0%	18,497	100.0%

Transmission constraint penalty factors should be applied without discretion, but not without additional rules that prevent unintended consequences. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints.[89] But the potential for prolonged and excessively high administrative pricing in the energy market due to transmission constraint penalty factors remains an issue that needs to be addressed. There can be situations in which the application of transmission penalty factors in real time for significant periods creates manipulation opportunities for virtuals and creates inefficient wealth transfers when market participants do not have the ability to react to the high prices either on the supply or demand side.[90] This could be the result of a lengthy planned transmission outage, for example.[91] It can also result from PJM reducing the control limit on the line rating in RT SCED below 100 percent of the actual line limit and triggering the transmission constraint penalty factor, while operating the system below the actual line limit for a prolonged period. PJM should not reduce the control limit on the transmission line ratings in SCED to trigger the inclusion of transmission constraint penalty factors in price. In addition, PJM has no information about the accuracy of the line ratings that are determined by each transmission owner. It is not clear whether the line ratings that trigger the transmission constraint penalty factors are defined for the actual expected period of the power flow on the line. Line ratings vary significantly by duration of power flows, and by ambient conditions.

PJM also revised the tariff to list the conditions under which transmission constraint penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020. On March 21, 2023, FERC approved new rules proposed by PJM to allow for reducing the transmission constraint penalty factors below the default $2,000 per MWh for constraints that are violated due to a transmission outage caused by the construction of upgrades to relieve congestion, for which limited generation resources are available to provide relief.[92]

PJM routinely, based on discretion, reduces the control limits on the transmission constraint line ratings modeled in SCED to below 100 percent, generally to 95 percent of the actual limit, administratively triggering the use of transmission constraint penalty factors.[93] The control limits set the limit of the constraint modeled in SCED. For example, in SCED, a transmission facility with a 100 MW line rating set at a 90 percent control limit would be modeled as a constraint with a limit of 90 MW. Table 3-57 shows the frequency of changes to the control limits for transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2025, there were 15,724, or 85 percent, of 18,497 violated transmission constraint intervals in the real-time market with a control limit less than 100 percent. In the first nine months of 2025, among the constraints

89 PJM applied a procedure that PJM termed constraint relaxation logic, under which a revised SCED dispatch solution was obtained with an artificially increased limit for the violated transmission facility. The logic typically resulted in reducing the shadow prices to be slightly below the defined constraint violation penalty factor.
90 See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).
91 See *id.*
92 See 182 FERC ¶ 61,183 (March 21, 2023). The Commission approved PJM's proposed tariff revisions to allow PJM to lower transmission constraint penalty factors generally for any situation similar to the high prices caused by Lanexa-Dunnsville-Northern Neck line outage in the Northern Neck peninsula in Virginia.
93 Actual transmission line limits are set by the transmission owner. PJM chooses the control limits. At present the actual line rating methods are not reviewed by FERC, or PJM, or the MMU.

with a reduced control limit, the constraint limit was reduced on average by 5.1 percent. In the first nine months of 2025, there were 101,632, or 97 percent, of 104,982 binding transmission constraint intervals in the real-time market with a control limit less than 100 percent. By arbitrarily lowering transmission facility limits, PJM is not using the full transmission system capacity available to serve the load to achieve the least cost dispatch solution. The cost to serve the load and the load payments would be lower had PJM not reduced the transmission line ratings.

Table 3-57 Frequency of reduction in control limit of line ratings (constraint intervals) in the real-time market: January through September, 2024 and 2025

	Frequency (Constraint Intervals)		Constraints with Reduced Control Percent (Constraint Intervals)		Average Reduction (Percent)	
Description	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)
Violated Transmission Constraints (Actual)	441	2,773	-	-	0.0%	0.0%
Violated Transmission Constraints (Reduced)	9,320	15,724	9,320	15,724	5.0%	5.1%
Binding Transmission Constraints	99,671	104,982	98,944	101,632	5.3%	5.8%
Market to Market Transmission Constraints	40,642	35,347	14,026	13,056	5.9%	7.2%
All Transmission Constraints	150,074	158,826	122,290	130,412	5.3%	5.9%

Table 3-58 shows the reasons provided by the PJM operators for changing the control limit on the line rating for violated transmission constraints. In the first nine months of 2025, of the 15,724 violated transmission constraint intervals with reduced control limits, no reason was provided for 12,698 cases, or 80.8 percent of all the cases. In 1,952 cases, or 12.4 percent, the control limits were reduced because the relief calculated by the SCED optimization was less than the operator's desired relief for the transmission constraint. In 13 cases, or 0.1 percent, the control limits were reduced because PJM designates the constraint as a thermal surrogate. Thermal surrogate constraints are constraints that PJM activates and for which PJM generally reduces the line rating to enable specific resources called on to control a constraint to set price.

The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP. This practice has significant market effects by limiting economic power flows and increasing prices above the level that would exist if 100 percent of the actual line rating were used in clearing the market and setting energy market prices.

Table 3-58 PJM's reasons for reduction in control limits of line ratings (constraint intervals) in the real-time market: January through September, 2024 and 2025

	Constraint Intervals		Average Reduction (Percent)	
Reason	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)
No reason provided	8,013	12,698	4.5%	4.4%
Prepositioning of generation resources to support an operational requirement	38	313	8.7%	8.7%
Inadequate relief calculated by the SCED optimization	897	1,952	6.7%	7.6%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	47	195	8.2%	7.6%
Modeled constraint is a thermal surrogate	101	13	21.2%	52.2%
Power flow on the constraint is volatile due to various system conditions	224	553	7.3%	7.3%
All violated constraints	9,320	15,724	5.0%	5.1%

Table 3-59 shows the impact on LMP of PJM dispatchers reducing the control limit of line ratings of transmission constraints and causing artificial line limit violations.[94] The transmission constraint penalty factor contribution to the load-weighted average LMP in the first nine months of 2025 was $5.31 per MWh or $3.25 billion of the total $30.9 billion cost of real-time load. This impact includes reductions to the line limits of violated constraints on high load summer days, June 23 and 24, 2025. If 100 percent of the line limits had been used for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load-weighted average LMP would have decreased to $0.03 per MWh, a 99.4 percent reduction.

Table 3-59 Real-time LMP effect of reduced control limits on transmission constraint line ratings (Dollars per MWh): January through September, 2024 and 2025

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2024 (Jan - Sep)	2025 (Jan - Sep)
Line Limits Reduced by PJM (Actual)	$3.23	$5.31
Hypothetical Use of Full Line Limits	$0.02	$0.03
Change in Contribution to LMP	($3.21)	($5.27)
Percent Change in Contribution to LMP	(99.4%)	(99.4%)

Table 3-60 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In the first nine months of 2025, there were 16,739, or 90 percent, violated transmission constraint intervals, which includes 1,032 violated transmission constraint intervals with actual line limits and 15,707 violated transmission constraint intervals with reduced line limits, in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

94 The MMU calculates the impact on system prices based on analysis using sensitivity factors. The transmission penalty factor contribution with actual line limits is not based on a counterfactual redispatch of the system. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-60 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals) in the real-time market: January through September, 2024 and 2025

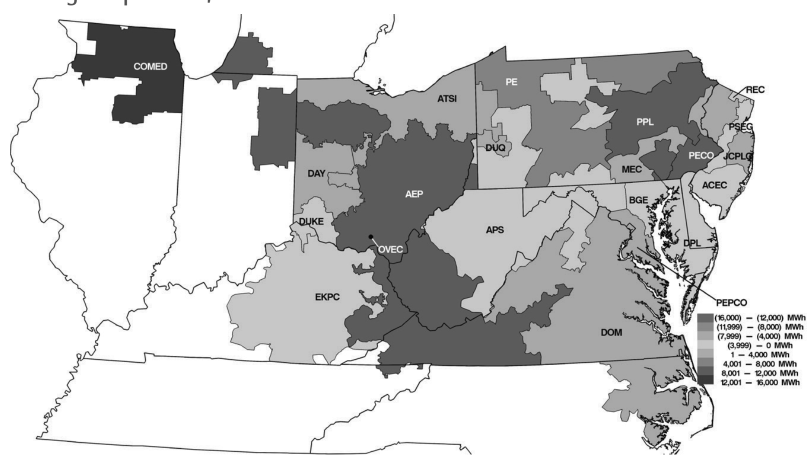
	2024 (Jan - Sep)			2025 (Jan - Sep)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
Violated Transmission Constraints (Actual)	96	-	345	1,032	-	1,741
Violated Transmission Constraints (Reduced)	9,215	-	105	15,707	-	17
Binding Transmission Constraints	99,470	-	201	102,497	-	2,485
Market to Market Transmission Constraints	5,811	17	34,814	8,703	19	26,625
All Transmission Constraints	114,592	17	35,465	127,939	19	30,868

Prior to September 1, 2022, transmission constraint penalty factors frequently set prices when PJM modeled a stability surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Since September 1, 2022, PJM uses a generator output limit constraint to manage generator voltage instability issues. In the first nine months of 2025, there were 11,264 constraint intervals during which PJM reduced the output of generators to manage instability. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the $2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

Net Generation by Zone

Figure 3-47 shows the difference between the PJM real-time generation and real-time load by zone for the first nine months of 2025. Figure 3-47 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. Table 3-61 shows the difference between the real-time generation and real-time load by zone for the first nine months of 2024 and 2025.

Figure 3-47 Map of real-time generation less real-time load by zone: January through September, 2025[95]



95 Real-time zonal generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

Table 3-61 Real-time generation less real-time load by zone (GWh): January through September, 2024 and 2025

Zonal Generation and Load (GWh)						
	2024 (Jan-Sep)			2025 (Jan-Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	1,267	7,578	(6,311)	632	7,491	(6,859)
AEP	118,845	96,745	22,100	124,054	102,527	21,527
APS	38,722	36,166	2,557	37,656	36,912	744
ATSI	41,609	50,204	(8,595)	40,512	50,593	(10,081)
BGE	12,880	22,983	(10,104)	12,929	23,008	(10,078)
COMED	103,850	69,542	34,308	106,540	71,211	35,329
DAY	1,589	13,028	(11,439)	2,184	13,306	(11,122)
DUKE	9,780	20,042	(10,262)	10,559	20,234	(9,674)
DOM	81,867	91,934	(10,066)	85,191	98,947	(13,756)
DPL	3,938	13,947	(10,009)	4,334	14,153	(9,819)
DUQ	11,882	10,244	1,638	12,722	9,938	2,784
EKPC	7,248	10,428	(3,180)	8,414	10,690	(2,277)
JCPLC	6,349	16,795	(10,446)	6,545	16,623	(10,077)
MEC	13,393	11,416	1,977	15,090	11,339	3,751
OVEC	7,041	86	6,955	8,326	84	8,241
PECO	56,999	29,197	27,802	56,936	29,221	27,715
PE	21,497	12,527	8,969	23,737	12,260	11,477
PEPCO	8,142	21,231	(13,089)	9,086	21,357	(12,271)
PPL	57,649	30,038	27,611	58,098	30,545	27,553
PSEG	32,922	32,551	371	32,448	32,196	252
REC	0	1,099	(1,099)	0	1,085	(1,085)

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, power to onsite customers, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during intervals when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during intervals when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-62 shows PJM generation by fuel source in GWh for the first nine months of 2024 and 2025.

In the first nine months of 2025, generation from coal units increased 16.1 percent, generation from natural gas units decreased 1.6 percent, generation from oil units increased 25.8 percent, generation from wind units increased 1.8 percent, and generation from solar units increased 46.4 percent compared to the first nine months of 2024.

Table 3-62 Generation (By fuel source (GWh)): January through September, 2024 and 2025[96 97]

	2024 (Jan-Sep)		2025 (Jan-Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	95,995.4	14.8%	111,408.4	16.7%	16.1%
Bituminous	83,607.3	12.9%	93,212.5	14.0%	11.5%
Sub Bituminous	7,668.9	1.2%	12,837.2	1.9%	67.4%
Other Coal	4,719.3	0.7%	5,358.7	0.8%	13.5%
Nuclear	203,815.3	31.5%	204,130.4	30.7%	0.2%
Gas	291,909.4	45.1%	287,121.7	43.1%	(1.6%)
Natural Gas CC	263,984.9	40.8%	256,754.7	38.6%	(2.7%)
Natural Gas CT	16,536.3	2.6%	17,712.2	2.7%	7.1%
Natural Gas Other Units	10,525.8	1.6%	11,853.6	1.8%	12.6%
Other Gas	862.3	0.1%	801.2	0.1%	(7.1%)
Hydroelectric	13,092.2	2.0%	12,696.9	1.9%	(3.0%)
Pumped Storage	5,188.7	0.8%	5,295.3	0.8%	2.1%
Run of River	6,264.7	1.0%	5,886.6	0.9%	(6.0%)
Other Hydro	1,638.8	0.3%	1,515.0	0.2%	(7.6%)
Wind	21,814.7	3.4%	22,209.4	3.3%	1.8%
Waste	2,936.2	0.5%	2,926.0	0.4%	(0.3%)
Oil	3,287.4	0.5%	4,136.1	0.6%	25.8%
Heavy Oil	119.8	0.0%	183.8	0.0%	53.4%
Light Oil	1,840.3	0.3%	2,549.8	0.4%	38.6%
Diesel	24.6	0.0%	107.1	0.0%	335.9%
Other Oil	1,302.8	0.2%	1,295.4	0.2%	(0.6%)
Solar	13,913.5	2.1%	20,375.1	3.1%	46.4%
Battery	38.0	0.0%	50.4	0.0%	32.6%
Biofuel	997.9	0.2%	931.6	0.1%	(6.6%)
Total	647,800.1	100.0%	665,986.1	100.0%	2.8%

96 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, power to run pumped hydro pumps or power to charge batteries.
97 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-63 Monthly generation (By fuel source (GWh)): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	18,584.7	12,714.7	9,375.7	9,538.0	8,603.3	13,359.0	17,631.6	12,981.8	8,619.7	111,408.4
Bituminous	15,606.7	10,857.9	7,860.0	7,909.4	7,006.1	11,232.4	14,629.5	10,960.9	7,149.6	93,212.5
Sub Bituminous	2,557.3	1,202.1	844.0	978.9	1,049.4	1,508.7	2,385.8	1,338.8	972.2	12,837.2
Other Coal	420.7	654.6	671.7	649.7	547.7	617.9	616.4	682.1	497.9	5,358.7
Nuclear	25,031.1	21,749.3	21,593.7	20,300.6	21,890.2	23,429.7	23,878.6	23,982.7	22,274.5	204,130.4
Gas	33,699.7	30,340.4	27,994.5	23,473.1	25,932.2	33,888.3	41,588.9	37,031.7	33,172.9	287,121.7
Natural Gas CC	30,743.0	28,555.0	26,549.2	20,085.1	24,006.2	29,429.0	34,787.3	32,711.1	29,888.8	256,754.7
Natural Gas CT	1,678.0	1,161.2	1,071.8	2,018.1	929.9	2,357.1	3,904.6	2,434.6	2,156.9	17,712.2
Natural Gas Other Units	1,193.1	550.2	292.3	1,287.3	917.1	2,007.8	2,767.3	1,788.4	1,050.1	11,853.6
Other Gas	85.7	74.1	81.1	82.6	79.0	94.4	129.7	97.6	77.0	801.2
Hydroelectric	1,197.5	1,221.5	1,601.9	1,272.6	1,730.5	1,881.7	1,731.0	1,181.3	878.9	12,696.9
Pumped Storage	507.4	512.6	512.9	452.1	548.2	722.9	813.1	690.6	535.5	5,295.3
Run of River	560.4	577.8	960.4	698.2	1,053.1	930.2	646.0	279.7	180.9	5,886.6
Other Hydro	129.7	131.1	128.7	122.3	129.1	228.5	272.0	211.0	162.5	1,515.0
Wind	3,907.9	3,085.7	4,259.4	3,256.9	2,656.6	1,776.2	1,088.0	1,119.9	1,058.9	22,209.4
Waste	332.5	303.5	309.3	329.9	347.3	303.4	348.5	348.2	303.3	2,926.0
Oil	668.6	303.8	183.2	306.9	268.4	570.3	914.6	478.4	441.9	4,136.1
Heavy Oil	77.1	2.8	0.0	7.2	3.5	33.5	34.6	22.3	2.8	183.8
Light Oil	379.3	158.1	86.9	139.2	104.5	393.9	688.3	273.2	326.4	2,549.8
Diesel	50.6	1.5	1.6	1.4	0.7	19.5	16.1	12.6	3.2	107.1
Other Oil	161.6	141.5	94.6	159.1	159.8	123.4	175.6	170.2	109.5	1,295.4
Solar	1,261.4	1,308.6	2,120.4	2,397.3	2,408.1	2,804.2	2,966.1	2,792.1	2,316.9	20,375.1
Battery	5.9	5.0	5.3	5.3	5.5	5.2	5.7	6.6	5.9	50.4
Biofuel	123.7	123.5	72.8	86.1	69.5	111.1	125.0	141.0	78.9	931.6
Total	84,813.1	71,156.0	67,516.2	60,966.6	63,911.5	78,129.2	90,278.2	80,063.6	69,151.7	665,986.1

Table 3-64 shows the difference between the day-ahead and the real-time average generation by fuel source.

Table 3-64 Day-ahead and real-time average generation (By fuel source (GWh)): January through September, 2025

	2025 (Jan -Sep)					
	Day-Ahead		Real-Time			Percent
	GWh	Percent	GWh	Percent	RT - DA	Difference
Coal	111,492.0	17.3%	111,408.4	16.7%	(83.6)	(0.1%)
Bituminous	93,258.8	14.5%	93,212.5	14.0%	(46.2)	(0.0%)
Sub Bituminous	13,207.6	2.0%	12,837.2	1.9%	(370.4)	(2.8%)
Other Coal	5,025.6	0.8%	5,358.7	0.8%	333.0	6.6%
Nuclear	201,065.7	31.2%	204,130.4	30.7%	3,064.7	1.5%
Gas	279,048.9	43.3%	287,121.7	43.1%	8,072.8	2.9%
Natural Gas CC	252,907.9	39.2%	256,754.7	38.6%	3,846.8	1.5%
Natural Gas CT	13,550.4	2.1%	17,712.2	2.7%	4,161.8	30.7%
Natural Gas Other Units	11,792.7	1.8%	11,853.6	1.8%	61.0	0.5%
Other Gas	798.0	0.1%	801.2	0.1%	3.2	0.4%
Hydroelectric	12,135.2	1.9%	12,696.9	1.9%	561.7	4.6%
Pumped Storage	6,420.4	1.0%	5,295.3	0.8%	(1,125.1)	(17.5%)
Run of River	5,714.7	0.9%	5,886.6	0.9%	171.9	3.0%
Other Hydro	0.0	0.0%	1,515.0	0.2%	1,515.0	NA
Wind	16,200.6	2.5%	22,209.4	3.3%	6,008.8	37.1%
Waste	2,872.0	0.4%	2,926.0	0.4%	54.1	1.9%
Oil	3,657.5	0.6%	4,136.1	0.6%	478.7	13.1%
Heavy Oil	103.8	0.0%	183.8	0.0%	80.0	77.0%
Light Oil	2,295.5	0.4%	2,549.8	0.4%	254.3	11.1%
Diesel	31.5	0.0%	107.1	0.0%	75.6	239.6%
Other Oil	1,226.6	0.2%	1,295.4	0.2%	68.8	5.6%
Solar	17,527.6	2.7%	20,375.1	3.1%	2,847.5	16.2%
Battery	16.4	0.0%	50.4	0.0%	34.0	207.8%
Biofuel	1,002.3	0.2%	931.6	0.1%	(70.7)	(7.1%)
Total	645,018.1	100.0%	665,986.1	100.0%	20,968.1	3.3%

Table 3-65 shows the share of generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2014.

Table 3-65 Share of generation by fuel source: January through September, 2014 through 2025

Jan - Sep	Natural Gas	Coal	Nuclear	Solar	Wind	Other Fuel Type
2014	17.0%	41.6%	36.6%	0.1%	1.8%	3.0%
2015	19.7%	38.6%	37.1%	0.1%	1.8%	2.8%
2016	24.1%	34.4%	36.5%	0.1%	2.0%	2.9%
2017	24.5%	31.7%	37.9%	0.2%	2.4%	3.3%
2018	29.5%	28.9%	35.1%	0.3%	2.4%	3.8%
2019	34.4%	25.1%	34.3%	0.3%	2.7%	3.3%
2020	40.0%	19.2%	34.2%	0.4%	2.9%	3.2%
2021	36.8%	24.0%	32.2%	0.9%	3.0%	3.1%
2022	39.6%	20.9%	31.9%	1.2%	3.4%	3.0%
2023	44.5%	15.0%	32.8%	1.4%	3.2%	3.1%
2024	44.9%	14.8%	31.5%	2.1%	3.4%	3.3%
2025	43.0%	16.7%	30.7%	3.1%	3.3%	3.2%

Fuel Diversity

Figure 3-48 shows the fuel diversity index (FDI_e) for PJM energy generation.[98] The FDI_e is defined as $\mathbf{1-\sum_{i=1}^{N} s_i^2}$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-62 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 27.9 percent from 2012 through September 2025. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light Zones and the increased shares of coal and nuclear that resulted.[99] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing renewable generation. Coal generation as a share of total generation was 55.0 percent for the first nine months of 2008 and 16.8 percent for the first nine months of 2025. Gas generation as a share of total generation was 7.7 percent for the first nine months of 2008 and 42.8 percent for the first nine months of 2025. Wind and solar generation as a share of total generation was 0.4 percent for the first nine months of 2008 and 6.5 percent for the first nine months of 2025.

The FDI_e increased 2.5 percent in the first nine months of 2025 compared to the first nine months of 2024. Increased coal generation in the first nine months of 2025 and less generation from gas fired generators led to the increase in the FDI_e.

The FDI_e was also used to measure the impact on fuel diversity of potential retirements in 2025 through 2030. A total of 34,733 MW of capacity are at risk of retirement, consisting of 4,684 MW currently planning to retire, 16,786 MW expected to retire for regulatory reasons and 13,264 MW expected to be uneconomic.[100] This capacity consists primarily of coal steam plants and CTs. The units expected to retire by the end of 2025 generated 34,394.2 GWh in the first nine months of 2025. The dashed line (green) in Figure 3-48 shows a counterfactual result for FDI_e assuming the 34,394.2 GWh of generation from uneconomic units and expected 2025 retirements were replaced by gas, wind and solar generation.[101] The FDI_e for the first nine months of 2025 under this counterfactual assumption would have been 1.6 percent lower than the actual FDI_e. The units expected to retire by the end of 2030 generated 65,235.4 GWh in the first nine months of 2025. Replacing this generation with gas, wind and solar generation results in a counterfactual FDI_e that is 1.2 percent lower than the actual FDI_e.[102] The dashed line (blue) in Figure 3-48 shows a counterfactual

98 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

99 See the *2019 Annual State of the Market Report for PJM*, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Zones occurred in October 2004.

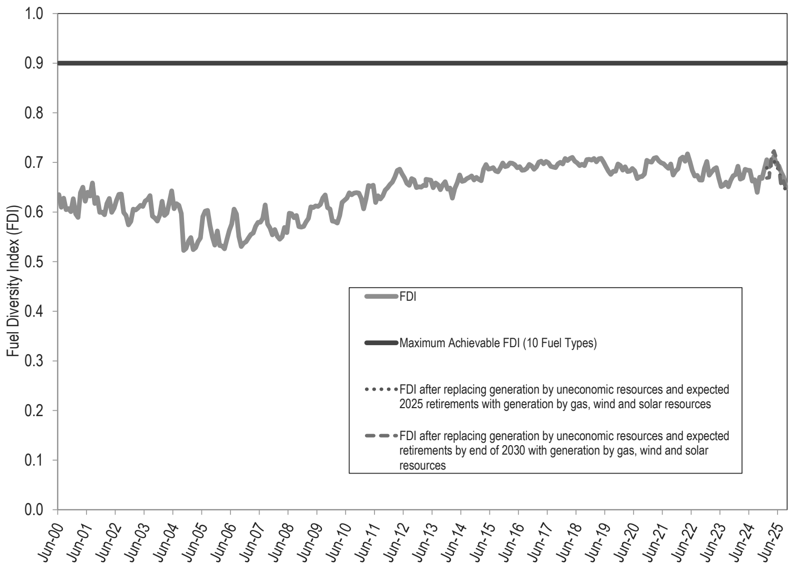
100 See Units At Risk of Retirement in the *2024 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

101 It is assumed that 8,962.7 GWh of the replacement energy will be from new wind and solar units. This value represents the increase over 2025 levels in renewable generation that is required by RPS in 2026. The split between solar (78.9 percent) and wind (21.1 percent) is based on queue data and 2025 capacity factors in Table 8-33 and Table 8-37.

102 It is assumed that 33,840.5 GWh of the replacement energy will be from new wind and solar units. This value represents the increase over 2025 levels in renewable generation that is required by RPS in 2030. The split between solar (78.9 percent) and wind (21.1 percent) is based on queue data and 2025 capacity factors in Table 8-33 and Table 8-37.

result for FDI_e assuming that this generation is replaced with gas, wind and solar generation.

Figure 3-48 Fuel diversity index for monthly generation: June 2000 through September 2025



Natural Gas Supply Issues

Both pipeline transportation and commodity natural gas are needed to deliver natural gas to power plants. Generators have a number of options which vary by pipeline and market area. A generator could purchase a delivered service in which the seller bundles the transportation and commodity, on a term contract or a spot basis. A generator could purchase pipeline transportation and commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Generators could purchase storage service. Storage services can be bundled with pipeline transportation, or storage and transportation purchased separately to move gas to or from a storage facility. The storage service will determine the total storage capacity and the injection and withdrawal rights. Storage offers the owner the ability to have on demand supplies, or the ability to redirect unused supplies to storage. Predetermined allocation (PDA) nominations can be used to direct the pipeline as to how to treat an excess or a deficiency of gas at a delivery point. Combinations of these options are also available.

Pipelines build transportation capacity and sell firm capacity to customers. Most of the transportation capacity is sold at tariff rates but in some cases negotiated rates are agreed to. A majority of firm capacity is contracted with gas utilities, gas marketers, industrial customers and generators. The purchasers of firm transportation capacity have the right to resell their capacity. Any such release must be done on the pipeline's electronic bulletin board. Bidders must be approved by the pipeline. When firm capacity on the pipelines is not being used, the pipeline tariffs provide for interruptible service.

In order to be able to actually use the purchased pipeline transportation service, pipelines may enforce nomination deadlines to require generation owners to nominate the flow of gas by defined deadlines. Some pipelines may also impose site specific restrictions that limit the ability of generators to nominate and schedule gas beyond the nomination deadlines. Table 3-66 shows the approved nomination deadlines and corresponding start time of gas flow.[103] Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-66 Approved nomination deadlines

	Nomination Cycle	Nom Deadline (EPT)	Time of Flow (EPT)	Bumping	Hours left in gas day for supply to flow
Day Before Flow	Timely	1400	1000		24
Day Before Flow	Evening	1900	1000	Yes	24
Day of Flow	Intraday 1	1100	1500	Yes	19
Day of Flow	Intraday 2	1530	1900	Yes	15
Day of Flow	Intraday 3	2000	2300	No	11

In 2024 and 2025, some interstate gas pipelines that provide service in the PJM service territory issued notices limiting the flexibility of firm and nonfirm transportation services. These notices include alerts, constraints, warnings of

103 Nomination deadlines approved in FERC Order No. 809, implemented April 1, 2016.

operational flow orders (OFO) and actual OFOs. These notices generally permit the pipelines to enforce nomination deadlines and to restrict the provision of gas to 24 hour ratable takes, meaning that nominations must be the same for each hour in the gas day. Pipelines may also enforce strict balancing constraints which limit the ability of gas users to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas. The pipelines providing service in the PJM service territory that issued notices were: ANR Pipeline, Columbia Gas Transmission, Cove Point, East Tennessee Natural Gas, Eastern Gas Transmission & Storage, Eastern Shore, Equitrans Transmission, Horizon Pipeline, Natural Gas Pipeline, Northern Border Pipeline, Texas Eastern, Tennessee Gas Pipeline and Transcontinental Gas Pipeline.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. The independent operations of geographically overlapping pipelines during extreme conditions highlight the shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of total supply and demand across a broad geographical area that includes multiple pipelines. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrate the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.

The increase in natural gas fired capacity in PJM, and the expected further increase, has highlighted issues with the dependence of PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, create risks for the bulk power system.

In general, the availability status of gas generators in the PJM energy market does not accurately reflect their ability to procure and nominate gas on the pipelines based on the rules defined by the pipelines. If the result of the pipeline rules is that some gas generators cannot reliably procure gas during the operating day in order to respond to PJM directions to generate, the result could be an inflated estimate of reserves on the PJM system, if the generator does not have back up fuel. Gas units should be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement.

PJM requires real-time situational awareness of the availability of all generators, including gas-fired generators, during the operating day, in order to operate the system effectively including knowledge of the level of available reserves. The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability.

Notification time is the period between PJM's notification and the beginning of the start sequence for a generating resource. Combustion turbines normally have notification times between six and 30 minutes. When pipelines require generators to nominate gas per the NAESB deadlines, generators must nominate gas well in advance and cannot start in six or 30 minutes. Instead, generators need significantly more time to nominate gas. This increase in the time needed should be requested and reflected in the units' notification time.

For example, the last nomination cycle available per NAESB is intraday 3 (ID3), see Table 3-66. The ID3 deadline is 20:00 EPT for gas that starts flowing at 23:00 (in three hours). The previous cycle, intraday 2 (ID2) deadline is at 15:30 EPT for gas that starts flowing at 19:00. A generator that has not nominated gas by ID2 cannot start until 23:00. Therefore, at 19:00, the unit has an implied time to start of four hours. Four hours is equal to 23:00 (the earliest the unit can start) minus 19:00. Table 3-67 shows the notification time gas fired generators should be requesting and submitting when pipelines require nominating per the NAESB cycle deadlines.

Table 3-67 Generator notification times when pipeline NAESB cycle deadlines are imposed

Hour	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
Notification Time	15	14	13	12	11	10	9	8	7	6	9	8
Time On (If Called)	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	19:00	19:00
Nearest Cycle	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID2	ID2

Hour	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Notification Time	7	6	9	8	7	6	5	20	19	18	17	16
Time On (If Called)	19:00	19:00	23:00	23:00	23:00	23:00	23:00	15:00	15:00	15:00	15:00	15:00
Nearest Cycle	ID2	ID2	ID3	ID3	ID3	ID3	ID3	ID1	ID1	ID1	ID1	ID1

The MMU proposed enhancements for situational awareness and transparency to improve the scheduling problem that PJM and gas fired units face, addressing how to reflect pipeline constraints in generator operating parameters, including how generators should submit notification times, and minimum run times and request temporary parameter exceptions.[104] The resultant guidelines were posted by the MMU and PJM on September 8, 2023.[105]

Types of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the day-ahead energy market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market that can set price via their offers and bids.

Table 3-68 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2025, coal units were 7.6 percent and natural gas units were 77.9 percent of marginal resources. In the first nine months of 2025, natural gas combined cycle units were 63.8 percent of marginal resources. In the first nine months of 2024, coal units were 11.0 percent and natural gas units were 74.8 percent of the total marginal resources. In the first nine months of 2024, natural gas combined cycle units were 61.5 percent of the total marginal resources. In the first nine months of 2025, 68.7 percent of the wind marginal units had negative offer prices, 30.2 percent had zero offer prices and 1.1 percent of the wind marginal units had positive offer prices. In the first nine months of 2024, 49.2 percent of the wind marginal units had negative offer prices, 40.7 percent had zero offer prices and 10.0 percent had positive offer prices.

The proportion of marginal nuclear units decreased from 0.35 percent in the first nine months of 2024 to 0.11 percent in the first nine months of 2025. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units have been offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

PJM implemented fast start pricing on September 1, 2021. The marginal resources shown in Table 3-68 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

104 "Gas Nomination Cycles and Units Operating Parameters," Electric Gas Coordination Senior Task Force (EGCSTF), August 15, 2023.
105 *See* Guidelines posted by the MMU and PJM: Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions. <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter_Limit_(PLS)_Exceptions_due_to_Pipeline_Restrictions_20230908.pdf>.

Table 3-68 Type of fuel used and technology (By real-time marginal units): January through September, 2021 through 2025[106]

		(Jan - Sep)				
Fuel	Technology	2021	2022	2023	2024	2025
Gas	CC	60.86%	60.40%	71.16%	61.48%	63.88%
Gas	CT	8.52%	11.53%	10.24%	9.99%	10.56%
Wind	Wind	8.93%	10.86%	4.75%	11.87%	10.34%
Coal	Steam	16.90%	10.73%	9.26%	11.01%	7.56%
Gas	Steam	1.07%	1.46%	1.78%	2.67%	2.55%
Oil	CT	1.06%	2.61%	0.52%	1.11%	1.58%
Other	Solar	1.04%	0.90%	0.01%	0.39%	1.16%
Oil	RICE	0.05%	0.04%	0.07%	0.07%	0.93%
Gas	RICE	0.53%	0.87%	1.15%	0.64%	0.93%
Uranium	Steam	0.81%	0.45%	0.51%	0.35%	0.11%
Oil	Steam	0.09%	0.02%	0.07%	0.19%	0.08%
Municipal Waste	RICE	0.00%	0.00%	0.06%	0.09%	0.08%
Municipal Waste	Steam	0.01%	0.03%	0.10%	0.07%	0.07%
Other	Steam	0.10%	0.05%	0.05%	0.06%	0.07%
Oil	CC	0.03%	0.04%	0.27%	0.02%	0.07%
Other	Battery	0.00%	0.00%	0.00%	0.01%	0.01%
Landfill Gas	CT	0.01%	0.00%	0.00%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	RICE	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 3-49 shows the type of fuel used by marginal resources in the real-time energy market for the first nine months of every year since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-49 Type of fuel used (By real-time marginal units): January through September, 2004 through 2025

106 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-69 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in the first nine months of 2025. In the first nine months of 2025, marginal fast start resources accounted for 7.91 percent of all marginal resources in the pricing run.

Table 3-69 Fuel type and technology (Real-time marginal units and fast start marginal units): January through September, 2025

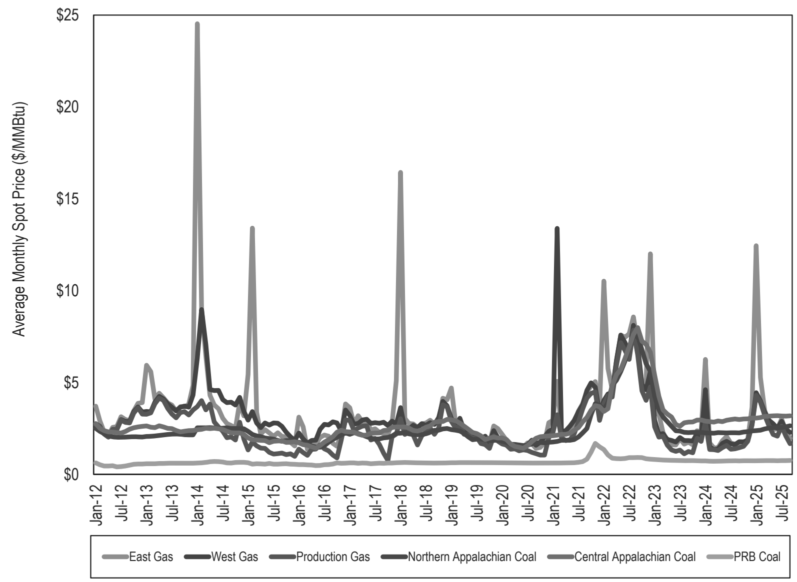
		2025 (Jan - Sep)		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	7.56%	7.56%
Gas	CC	0.00%	63.88%	63.88%
Gas	CT	5.29%	5.28%	10.56%
Gas	RICE	0.92%	0.01%	0.93%
Gas	Steam	0.00%	2.55%	2.55%
Landfill Gas	CT	0.00%	0.00%	0.00%
Municipal Waste	RICE	0.01%	0.07%	0.08%
Municipal Waste	Steam	0.00%	0.07%	0.07%
Oil	CC	0.00%	0.07%	0.07%
Oil	CT	0.63%	0.95%	1.58%
Oil	RICE	0.93%	0.00%	0.93%
Oil	Steam	0.00%	0.08%	0.08%
Other	Battery	0.00%	0.01%	0.01%
Other	Solar	0.04%	1.12%	1.16%
Other	Steam	0.00%	0.07%	0.07%
Uranium	Steam	0.00%	0.11%	0.11%
Wind	Wind	0.09%	10.25%	10.34%
All Marginal Units		7.91%	92.09%	100.00%

Fuel Price Trends and LMP

In a competitive market, changes in LMP follow changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of short run marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs also contribute to changes in the marginal cost of marginal units.

Figure 3-50 shows fuel prices in PJM for 2012 through September 2025. Natural gas prices and coal prices increased and oil prices decreased in the first nine months of 2025 compared to the first nine months of 2024. In the first nine months of 2025, the price of eastern natural gas was 83.4 percent higher and the price of western natural gas was 59.2 percent higher than in the first nine months of 2025. The price of Northern Appalachian coal was 11.4 percent higher; the price of Central Appalachian coal was 7.8 percent higher; and the price of Powder River Basin coal was 2.5 percent higher.[107] The price of ULSD NY Harbor Barge (ultra low sulfur diesel) was 6.4 percent lower in the first nine months of 2025 than in the first nine months of 2024.

Figure 3-50 Spot average fuel price comparison: 2012 through September 2025 ($/MMBtu)



107 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Components of LMP

Components of Real-Time Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and up to fourteen minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, and New Jersey.[108] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and reserves. When generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. The component, ancillary service redispatch cost, shows the contribution of this cost to the PJM's load-weighted LMP. In addition, in periods when the pricing run solution does not meet the reserve requirements, PJM invokes shortage pricing, based on the operating reserve demand curve. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity component, which is defined by the operating reserve demand curve.[109]

Starting on September 1, 2021, the components shown in Table 3-70 and Table 3-72 are from the pricing run, which includes the impact of amortized start cost and amortized no load cost of the fast start marginal units. The components of LMP are shown in Table 3-70, including markup using unadjusted cost-based offers.[110] Table 3-70 shows that in the first nine months of 2025, 7.2 percent of the load-weighted LMP was the result of coal costs, 43.4 percent was the result of gas costs and 4.1 percent was the result of the cost of carbon emission allowances. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. Using unadjusted cost-based offers, negative markup was -7.4 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 7.2 percent of the load-weighted LMP. LMP may, at times, be set by transmission constraint penalty factors. In the first nine months of 2025, 10.5 percent of the load-weighted LMP was the result of transmission penalty factors. More than 99 percent of this impact occurred as a result of PJM's reduction to line ratings in SCED. The percent contribution of transmission penalty factors has increased substantially since PJM allowed penalty factors to affect LMPs starting February 1, 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first nine months of 2024 and 2025.

108 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021, and left RGGI on December 31, 2023. Litigation over Virginia's participation is pending. See Virginia Court of Appeals (Case No. 1494-23-4).

109 Scarcity component includes ancillary service redispatch cost component during periods of scarcity.

110 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www. monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-70 Components of real-time (Unadjusted) load-weighted average LMP: January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$13.00	37.9%	$21.94	43.4%	5.6%
Transmission Constraint Penalty Factor	$3.23	9.4%	$5.31	10.5%	1.1%
Positive Markup	$3.94	11.5%	$3.64	7.2%	(4.3%)
Coal	$4.17	12.1%	$3.62	7.2%	(5.0%)
Variable Maintenance	$3.28	9.6%	$3.46	6.8%	(2.7%)
Ten Percent Adder	$1.99	5.8%	$3.06	6.1%	0.3%
Oil	$1.08	3.1%	$2.66	5.3%	2.1%
CO_2 Cost	$1.91	5.6%	$2.08	4.1%	(1.4%)
NA	$0.11	0.3%	$1.46	2.9%	2.6%
Scarcity	$0.18	0.5%	$1.32	2.6%	2.1%
Variable Operations	$1.46	4.3%	$1.30	2.6%	(1.7%)
Ancillary Service Redispatch Cost	$1.41	4.1%	$1.21	2.4%	(1.7%)
Opportunity Cost Adder	$1.37	4.0%	$1.17	2.3%	(1.7%)
Emergency Demand Response	$0.00	0.0%	$0.89	1.8%	1.8%
Market-to-Market	$0.30	0.9%	$0.59	1.2%	0.3%
Increase Generation Differential	$0.24	0.7%	$0.50	1.0%	0.3%
LPA Rounding Difference	$0.20	0.6%	$0.38	0.8%	0.2%
Landfill Gas	$0.05	0.1%	$0.08	0.2%	0.0%
NO_x Cost	$0.11	0.3%	$0.07	0.1%	(0.2%)
Other	$0.02	0.1%	$0.02	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
PJM Administrative Cap	$0.00	0.0%	($0.11)	(0.2%)	(0.2%)
Renewable Energy Credits	($0.05)	(0.1%)	($0.14)	(0.3%)	(0.1%)
Decrease Generation Differential	($0.05)	(0.1%)	($0.25)	(0.5%)	(0.3%)
Negative Markup	($3.64)	(10.6%)	($3.74)	(7.4%)	3.2%
Total	$34.31	100.0%	$50.51	100.0%	0.0%

Components of Change in LMP

Table 3-71 shows the components of the increase in real-time load-weighted average LMP from the first nine months of 2024 to the first nine months of 2025. In the first nine months of 2025, the real-time load-weighted average LMP increased by $16.20 per MWh, 47.2 percent. Fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations) increased the LMP by $9.85 per MWh, 60.8 percent of increase in LMP. The emissions cost components of LMP (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) decreased the LMP by $0.16 per MWh, -1.0 percent of the increase in LMP. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the LMP $0.85 per MWh, 5.2 percent of the increase in LMP. The scarcity component increased the LMP by $1.14 per MWh, 7.0 percent of the increase in the LMP. The transmission constraint penalty factor increased the LMP by $2.07 per MWh, 12.8 percent, primarily as a result of PJM's reduction of line ratings in SCED. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, decreased the LMP by $0.21 per MWh, -1.3 percent. The pre-emergency demand response called on by PJM during the hot weather days in June increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.11 per MWh, a 0.7 percent decrease.

Table 3-71 Components of Change in real-time load-weighted average LMP: January through September, 2024 and 2025

Component	2024 (Jan - Sep)	2025 (Jan - Sep)	Change in LMP	Percent of Total Change
Fuel and Consumables	$19.75	$29.59	$9.85	60.8%
Emission Related	$3.34	$3.18	($0.16)	(1.0%)
Market Power Related	$5.57	$6.42	$0.85	5.2%
Scarcity	$0.18	$1.32	$1.14	7.0%
Transmission Constraint Penalty Factor	$3.23	$5.31	$2.07	12.8%
Ancillary Service Redispatch Cost	$1.41	$1.21	($0.21)	(1.3%)
Pre-emergency Demand Response	$0.00	$0.89	$0.89	5.5%
PJM Administrative Cap	$0.00	($0.11)	($0.11)	(0.7%)
All Other	$0.82	$2.71	$1.89	11.6%
Total Change	$34.31	$50.51	$16.20	100.0%

In order to understand the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-70) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-72), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

Table 3-72 Components of real-time (Adjusted) load-weighted average LMP: January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$13.00	37.9%	$21.94	43.4%	5.6%
Positive Markup	$4.90	14.3%	$5.43	10.7%	(3.5%)
Transmission Constraint Penalty Factor	$3.23	9.4%	$5.31	10.5%	1.1%
Coal	$4.17	12.1%	$3.62	7.2%	(5.0%)
Variable Maintenance	$3.28	9.6%	$3.46	6.8%	(2.7%)
Oil	$1.08	3.1%	$2.66	5.3%	2.1%
CO_2 Cost	$1.91	5.6%	$2.08	4.1%	(1.4%)
NA	$0.11	0.3%	$1.46	2.9%	2.6%
Scarcity	$0.18	0.5%	$1.32	2.6%	2.1%
Variable Operations	$1.46	4.3%	$1.30	2.6%	(1.7%)
Ancillary Service Redispatch Cost	$1.41	4.1%	$1.21	2.4%	(1.7%)
Opportunity Cost Adder	$1.37	4.0%	$1.17	2.3%	(1.7%)
Emergency Demand Response	$0.00	0.0%	$0.89	1.8%	1.8%
Market-to-Market	$0.30	0.9%	$0.59	1.2%	0.3%
Increase Generation Differential	$0.24	0.7%	$0.50	1.0%	0.3%
LPA Rounding Difference	$0.20	0.6%	$0.38	0.8%	0.2%
Landfill Gas	$0.05	0.1%	$0.08	0.2%	0.0%
NO_x Cost	$0.11	0.3%	$0.07	0.1%	(0.2%)
Other	$0.02	0.1%	$0.02	0.0%	(0.0%)
Ten Percent Adder	$0.01	0.0%	$0.01	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
PJM Administrative Cap	$0.00	0.0%	($0.11)	(0.2%)	(0.2%)
Renewable Energy Credits	($0.05)	(0.1%)	($0.14)	(0.3%)	(0.1%)
Decrease Generation Differential	($0.05)	(0.1%)	($0.25)	(0.5%)	(0.3%)
Negative Markup	($2.62)	(7.6%)	($2.48)	(4.9%)	2.7%
Total	$34.31	100.0%	$50.51	100.0%	0.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-73, including markup using unadjusted cost-based offers for in the first nine months of 2025. The variable maintenance cost component is the component with the largest change in the share of total LMP from the dispatch run to the pricing run is, constituting 4.5 percent of the dispatch run LMP and 6.8 percent of the pricing run LMP.

Table 3-73 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: January through September, 2025

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$20.45	44.1%	$21.94	43.4%	(0.7%)
Transmission Constraint Penalty Factor	$5.25	11.3%	$5.31	10.5%	(0.8%)
Positive Markup	$3.34	7.2%	$3.64	7.2%	0.0%
Coal	$4.08	8.8%	$3.62	7.2%	(1.6%)
Variable Maintenance	$2.10	4.5%	$3.46	6.8%	2.3%
Ten Percent Adder	$2.75	5.9%	$3.06	6.1%	0.1%
Oil	$1.93	4.2%	$2.66	5.3%	1.1%
CO_2 Cost	$2.08	4.5%	$2.08	4.1%	(0.4%)
NA	$1.42	3.1%	$1.46	2.9%	(0.2%)
Scarcity	$1.04	2.2%	$1.32	2.6%	0.4%
Variable Operations	$1.28	2.8%	$1.30	2.6%	(0.2%)
Ancillary Service Redispatch Cost	$0.75	1.6%	$1.21	2.4%	0.8%
Opportunity Cost Adder	$1.08	2.3%	$1.17	2.3%	(0.0%)
Emergency Demand Response	$0.95	2.0%	$0.89	1.8%	(0.3%)
Market-to-Market	$0.51	1.1%	$0.59	1.2%	0.1%
Increase Generation Differential	$0.50	1.1%	$0.50	1.0%	(0.1%)
LPA Rounding Difference	$0.27	0.6%	$0.38	0.8%	0.2%
Landfill Gas	$0.09	0.2%	$0.08	0.2%	(0.0%)
NO_x Cost	$0.06	0.1%	$0.07	0.1%	0.0%
Other	$0.02	0.0%	$0.02	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
PJM Administrative Cap	$0.00	0.0%	($0.11)	(0.2%)	(0.2%)
Renewable Energy Credits	($0.15)	(0.3%)	($0.14)	(0.3%)	0.1%
Decrease Generation Differential	($0.21)	(0.5%)	($0.25)	(0.5%)	(0.0%)
Negative Markup	($3.23)	(7.0%)	($3.74)	(7.4%)	(0.4%)
Total	$46.34	100.0%	$50.51	100.0%	0.0%

The components of the total cost to real-time load ($M) are shown in Table 3-74, including markup using unadjusted cost-based offers. The components of the total cost to real-time load are shown in Table 3-75, including markup using adjusted cost-based offers. In the first nine months of 2025, the cost of real-time load increased by $10,488.1 million or 51.1 percent. Of the $30,996.6 million in the total cost of real-time load in the first nine months of 2025, $13,463.2 million is due to the cost of gas, $3,255.9 million is due to the transmission penalty factor, $2,234.5 million is due to the positive markup, $2,218.7 million is due to the cost of coal, $2,122.1 million is due to the variable maintenance and $1,876.2 million is due to the ten percent adder.

Table 3-74 Components of the cost of real-time (Unadjusted) load: January through September, 2024 and 2025

	Contribution to Real Time Cost of Load ($Million)			
Element	2024 (Jan - Sep)	2025 (Jan - Sep)	Change	Percent
Gas	$7,769.0	$13,463.2	$5,694.1	54.3%
Transmission Constraint Penalty Factor	$1,931.7	$3,255.9	$1,324.2	12.6%
Positive Markup	$2,357.3	$2,234.5	($122.8)	(1.2%)
Coal	$2,491.0	$2,218.7	($272.2)	(2.6%)
Variable Maintenance	$1,962.5	$2,122.1	$159.6	1.5%
Ten Percent Adder	$1,186.6	$1,876.2	$689.6	6.6%
Oil	$643.4	$1,631.6	$988.2	9.4%
CO_2 Cost	$1,141.0	$1,276.8	$135.8	1.3%
NA	$64.0	$897.7	$833.7	7.9%
Scarcity	$105.9	$809.5	$703.5	6.7%
Variable Operations	$873.1	$795.9	($77.2)	(0.7%)
Ancillary Service Redispatch Cost	$845.7	$739.7	($106.0)	(1.0%)
Opportunity Cost Adder	$817.7	$716.5	($101.1)	(1.0%)
Emergency Demand Response	$0.0	$545.0	$545.0	5.2%
Market-to-Market	$180.8	$364.1	$183.4	1.7%
Increase Generation Differential	$144.2	$307.6	$163.4	1.6%
LPA Rounding Difference	$121.6	$234.0	$112.4	1.1%
Landfill Gas	$27.1	$51.5	$24.4	0.2%
NO_x Cost	$67.0	$41.6	($25.5)	(0.2%)
Other	$10.9	$9.7	($1.2)	(0.0%)
SO_2 Cost	$0.2	$0.1	($0.1)	(0.0%)
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
PJM Administrative Cap	$0.0	($68.0)	($68.0)	(0.6%)
Renewable Energy Credits	($27.0)	($83.9)	($56.9)	(0.5%)
Decrease Generation Differential	($29.4)	($151.0)	($121.6)	(1.2%)
Negative Markup	($2,175.7)	($2,292.3)	($116.6)	(1.1%)
Total	$20,508.5	$30,996.6	$10,488.1	100.0%

Table 3-75 Components of the (Adjusted) cost of real-time load: January through September, 2024 and 2025

	Contribution to Real Time Cost of Load ($Million)			
Element	2024 (Jan - Sep)	2025 (Jan - Sep)	Change	Percent
Gas	$7,769.0	$13,463.2	$5,694.1	54.3%
Positive Markup	$2,930.7	$3,331.7	$400.9	3.8%
Transmission Constraint Penalty Factor	$1,931.7	$3,255.9	$1,324.2	12.6%
Coal	$2,491.0	$2,218.7	($272.2)	(2.6%)
Variable Maintenance	$1,962.5	$2,122.1	$159.6	1.5%
Oil	$643.4	$1,631.6	$988.2	9.4%
CO_2 Cost	$1,141.0	$1,276.8	$135.8	1.3%
NA	$63.9	$897.5	$833.6	7.9%
Scarcity	$105.9	$809.5	$703.5	6.7%
Variable Operations	$873.1	$795.9	($77.2)	(0.7%)
Ancillary Service Redispatch Cost	$845.7	$739.7	($106.0)	(1.0%)
Opportunity Cost Adder	$817.7	$716.5	($101.1)	(1.0%)
Emergency Demand Response	$0.0	$545.0	$545.0	5.2%
Market-to-Market	$180.8	$364.1	$183.4	1.7%
Increase Generation Differential	$144.2	$307.6	$163.4	1.6%
LPA Rounding Difference	$121.6	$234.0	$112.4	1.1%
Landfill Gas	$27.1	$51.5	$24.4	0.2%
NO_x Cost	$67.0	$41.6	($25.5)	(0.2%)
Other	$10.9	$9.7	($1.2)	(0.0%)
Ten Percent Adder	$4.5	$6.9	$2.4	0.0%
SO_2 Cost	$0.2	$0.1	($0.1)	(0.0%)
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
PJM Administrative Cap	$0.0	($68.0)	($68.0)	(0.6%)
Renewable Energy Credits	($27.0)	($83.9)	($56.9)	(0.5%)
Decrease Generation Differential	($29.4)	($151.0)	($121.6)	(1.2%)
Negative Markup	($1,567.1)	($1,520.1)	$47.0	0.4%
Total	$20,508.5	$30,996.6	$10,488.1	100.0%

Table 3-76 shows the components of the increase in the cost of real-time load from the first nine months of 2024 to the first nine months of 2025. In the first nine months of 2025, the cost of real-time load increased $10,488.1 million. Fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations) increased the cost of real-time load by $6,357.3 million, 60.6 percent of the increase in the cost of real-time load. The emissions cost components (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) decreased the real-time cost of load by $47.9 million, -0.5 percent of the increase in the cost of real-time load. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the cost of real-time load by $609.8 million, 5.8 percent of the increase in the cost of real time load. The scarcity component increased the cost of real-time load by $703.5 million, 6.7 percent of the increase in the cost of real-time load. The transmission constraint penalty factor increased the cost of real-time load by $1,324.2 million, 12.6 percent. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, decreased the cost of real-time load by $106.0, 1.0 percent of the cost of real time load. The emergency demand response called on by PJM during the hot weather days in June and July increased the cost of real time load by $545.0 million, 5.2 percent of the increase in the cost of real time load. The cost of real time load would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap on SMP. The administrative cap reduced the cost of real time load by $68.0 million, a 0.6 percent decrease.

Table 3-76 Components of Change in the cost of real-time load: January through September, 2024 and 2025

	($ Million)			
Component	2024 (Jan - Sep)	2025 (Jan - Sep)	Change	Percent of Total Change
Fuel and Consumables	$11,803.5	$18,160.8	$6,357.3	60.6%
Emission Related	$1,999.0	$1,951.1	($47.9)	(0.5%)
Market Power Related	$3,330.6	$3,940.4	$609.8	5.8%
Scarcity	$105.9	$809.5	$703.5	6.7%
Transmission Constraint Penalty Factor	$1,931.7	$3,255.9	$1,324.2	12.6%
Ancillary Service Redispatch Cost	$845.7	$739.7	($106.0)	(1.0%)
Pre-emergency Demand Response	$0.0	$545.0	$545.0	5.2%
PJM Administrative Cap	$0.0	($68.0)	($68.0)	(0.6%)
All Other	$492.0	$1,662.1	$1,170.1	11.2%
Total Change	$20,508.5	$30,996.6	$10,488.1	100.0%

Components of Day-Ahead Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Table 3-77 shows the components of the PJM day-ahead annual load-weighted average LMP. In the first nine months of 2025, 12.2 percent of the load-weighted LMP was the result of gas costs, 7.2 percent of the load-weighted LMP was the result of coal costs, 18.3 percent was the result of INCs, 33.2 percent was the result of DECs, 4.0 percent was the result of UTCs, and 7.1 percent was the result of positive markup.[111]

Table 3-77 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): April through September, 2025

	2025 (Apr - Sep)	
Element	Contribution to LMP	Percent
DEC	$15.92	33.2%
INC	$8.79	18.3%
Gas	$5.86	12.2%
NA	$5.07	10.6%
Coal	$3.46	7.2%
Positive Markup	$3.39	7.1%
Up to Congestion	$1.92	4.0%
Variable Maintenance	$1.20	2.5%
Ten Percent Adder	$1.12	2.3%
Variable Operations	$0.88	1.8%
Ancillary Service Redispatch Cost	$0.79	1.6%
CO_2 Cost	$0.69	1.4%
Oil	$0.32	0.7%
Increase Generation Differential	$0.13	0.3%
Opportunity Cost Adder	$0.07	0.1%
NO_x Cost	$0.05	0.1%
Other	$0.01	0.0%
SO_2 Cost	$0.00	0.0%
Landfill Gas	$0.00	0.0%
Decrease Generation Differential	($0.00)	(0.0%)
Scarcity	($0.01)	(0.0%)
Transmission Constraint Penalty Factor	($0.02)	(0.0%)
Negative Markup	($0.76)	(1.6%)
Renewable Energy Credits	($0.88)	(1.8%)
Total	$48.00	100.0%

111 MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors requires accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate the component breakdown for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

Table 3-78 shows the components of the PJM day-ahead annual load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas and oil units.[112]

Table 3-78 Components of day-ahead (Adjusted) load-weighted average LMP (Dollars per MWh): April through September, 2025

	2025 (Apr - Sep)	
Element	Contribution to LMP	Percent
DEC	$15.92	33.2%
INC	$8.79	18.3%
Gas	$5.86	12.2%
NA	$5.07	10.6%
Positive Markup	$4.07	8.5%
Coal	$3.46	7.2%
Up to Congestion	$1.92	4.0%
Variable Maintenance	$1.20	2.5%
Variable Operations	$0.88	1.8%
Ancillary Service Redispatch Cost	$0.79	1.6%
CO_2 Cost	$0.69	1.4%
Oil	$0.32	0.7%
Increase Generation Differential	$0.13	0.3%
Opportunity Cost Adder	$0.07	0.1%
NO_x Cost	$0.05	0.1%
Other	$0.01	0.0%
Ten Percent Adder	$0.00	0.0%
SO_2 Cost	$0.00	0.0%
Landfill Gas	$0.00	0.0%
Decrease Generation Differential	($0.00)	(0.0%)
Scarcity	($0.01)	(0.0%)
Transmission Constraint Penalty Factor	($0.02)	(0.0%)
Negative Markup	($0.31)	(0.7%)
Renewable Energy Credits	($0.88)	(1.8%)
Total	$48.00	100.0%

112 Id.

Shortage

PJM's real-time energy market experienced five-minute shortage pricing for one or more reserve products for 130 unique five-minute intervals across 22 days in the first nine months of 2025. PJM implemented fast start pricing on September 1, 2021, creating the possibility that the pricing run and the dispatch run could classify different intervals as short. In the first nine months of 2025, there were 130 unique five-minute intervals with real-time shortage pricing in the pricing run for one or more reserve products, and 111 unique intervals with real-time shortage pricing in the dispatch run for one or more reserve products.

Emergency Procedures

PJM issues advisories usually several days in advance to notify members of possible emergency actions that could be taken during the operating day. PJM declares alerts at least a day prior to the operating day to notify members of possible emergency actions that could be taken during the operating day. In real time, on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

Some emergency actions serve as triggers for performance assessment intervals (PAIs) when declared for the RTO or the active subzone. Some emergency actions trigger PAIs unconditionally while others only trigger PAIs when there is a primary reserve shortage for that area.[113] [114] The declaration of such emergency actions for smaller areas, such as for specific control zones, does not trigger a PAI. When communicating emergency procedures, PJM will also post NERC energy emergency alert (EEA) levels.[115] Table 3-79 provides a

113 See PJM. "PJM Manual 18: PJM Capacity Market," § 8.4A Non-Performance Assessment, Rev. 61 (Jul. 23, 2025).
114 OATT, Part I (Common Service Provisions) § 1.
115 NERC Attachment 1-EOP-011-4. "Energy Emergency Alerts," February 15, 2024. <https://www.nerc.com/pa/Stand/Reliability%20 Standards/EOP-011-4.pdf>.

description of PJM declared emergency procedures, in alphabetical order, including whether they are a trigger for PAIs and the NERC EEA level triggered with the procedure, if any.[116] [117] [118] [119]

Table 3-79 Description of emergency procedures

Emergency Procedure	Priority Level	Triggers NERC Energy Emergency Alert	Triggers Performance Assessment Interval	Purpose
Cold Weather Advisory	Advisory			To notify personnel and facilities that PJM may issue a Cold Weather Alert.
Cold Weather Alert	Alert			To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Conservative Operations	Alert			To notify personnel and facilities that PJM may operate more conservatively. This can be due to natural phenomena, weather events, security events, and other conditions. Conservative operations may result in the use of larger contingencies and stricter transfer limits.
Emergency Energy Bids Requested	Informational			To request bids for emergency energy after declaring a Maximum Emergency Generation Action.
Emergency Mandatory Load Management Reduction Action	Action	EEA2		To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Geomagnetic Disturbance Action	Action			To inform members that PJM will operate the grid with more conservative transfer limits developed for such disturbances. Transmission owners must coordinate with PJM before acting upon their own disturbance procedures.
Geomagnetic Disturbance Warning	Warning			To warn members than the National Oceanic and Atmospheric Administration predict a possible geomagnetic storm of severity K7 or greater, which can induce currents in the system and equipment.
High System Voltage Action	Action			To prepare the system for possible high voltages and to coordinate with transmission owners and generation owners for managing those high voltages.
Hot Weather Alert	Alert			To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Load Shed Directive	Action		Yes	To shed load in a local area, reserve subzone, or the entire RTO. A load shed directive for the reserve subzone or the entire RTO triggers a Performance Assessment Interval.
Low Voltage Alert	Alert			To alert transmission owners and generation owners that a period of low voltage and high load are expected.
Maintenance Outage Recall	Informational			To request that generation owners make units available by canceling any maintenance outages within at least 72 hours of posting. After that time, maintenance outages are converted into forced outages.
Maximum Emergency Action	Action		Yes with PR shortage	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Maximum Emergency Generation Alert	Alert	EEA1		To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Non-Market Post Contingency Local Load Relief Warning	Warning			To warn transmission owners of the possibility of load shed in their area for non-market facilities.
Post Contingency Local Load Relief Warning	Warning			To warn transmission owners of the possibility of load shed in their area.
Pre-Emergency Mandatory Load Management Reduction Action	Action			To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Transmission Loading Relief (TLR)	Informational			To maintain transmission operating security limits. This can involve curtailing external transactions and charging outside customers for the cost of congestion.
Unit Startup Notification Alert	Alert			To direct generation owners to prepare units so that long lead time units can come online within 48 hours. This notice is given days in advance of the predicted need.
Voltage Reduction Action	Action	EEA2 or EEA3 depending on circumstance	Yes	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.

116 See PJM. "PJM Manual 13: Emergency Operations," § 3.3 Cold Weather Advisory / Alert, Rev. 94 (Dec. 18, 2024).
117 See PJM. "PJM Manual 13: Emergency Operations," § 3.4 Hot Weather Alert, Rev. 94 (Dec. 18, 2024).
118 See PJM. "PJM Manual 13: Emergency Operations,"§ 2.3.1 Advanced Notice Emergency Procedures: Alerts, Rev. 94 (Dec. 18, 2024).
119 See PJM. "PJM Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 94 (Dec. 18, 2024).

Not all emergency procedures defined in Table 3-79 are included in Table 3-80, Table 3-81, Figure 3-51, Figure 3-52, Figure 3-54 and Figure 3-55, even if they occurred in the first nine months of 2025. Synchronized reserve events are covered in more detail in Section 10. Information about frequent events is treated separately. Post Contingency Local Load Relief Warnings (PCLLRWs) and Non-Market Post Contingency Local Load Relief Warnings (NMPCLLRWs) are shown in Figure 3-56 and Figure 3-57. Transmission loading relief informational postings (TLRs) are discussed in other sections of this report. Local load relief warnings provide to transmission owners advanced warning of possible local load shed in an area in order to relieve a local constraint and are separate from manual load dump warnings. Transmission loading relief is a NERC procedure for curtailing interchange transactions to avoid violating operational limits of the system.[120] [121]

Table 3-80 shows the dates affected by emergency alerts, warnings, actions, and informational postings in the first nine months of 2025. Events in Table 3-80 can span multiple days, but only the first day is shown. Advisories, alerts, warnings, and informational postings do not necessarily take effect immediately. For example, for cold weather alerts, the dates affected are when PJM expects the cold weather requiring the alert to occur. For maintenance outage recalls, the dates affected are from the date PJM initiates the recall until the date the units are expected to be available. Figure 3-51 shows the timeline of the advisories, alerts, warnings, actions, and the maintenance outage recall during the January 2025 polar vortex. Figure 3-52 shows the timeline of the alerts, actions, and the maintenance outage recall during the June 2025 hot weather event. Figure 3-53 shows the timeline of the alerts, actions, and the maintenance outage recall during the July 2025 heatwave.

120 NERC IRO-006-5. "Reliability Coordination – Transmission Loading Relief (TLR)," November 4, 2010. <https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-5.pdf>.
121 NERC IRO-006-EAST-2. "Transmission Loading Relief Procedure for the Eastern Interconnection," August 13, 2015. <https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-EAST-2.pdf>.

Table 3-80 Starting days of declared emergency alerts, warnings actions, and certain informational postings: January through September, 2025

Date	Cold Weather Alert	Hot Weather Alert	Conservative Operations	Emergency Energy Request	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Geomagnetic Disturbance Warning	Geomagnetic Disturbance Action	Low Voltage Alert	High System Voltage Action	Load Shed Directive	Unit Startup Notification Alert	Maintenance Outage Recall	Maximum Emergency Generation Alert	Maximum Emergency Generation Action	Voltage Reduction Action
01-Jan-2025							PJM RTO									
08-Jan-2025	Western															
14-Jan-2025	Western															
15-Jan-2025													PJM RTO			
19-Jan-2025									PJM RTO							
20-Jan-2025	PJM RTO		PJM RTO													
22-Jan-2025														PJM RTO		
16-Feb-2025			PJM RTO													
17-Feb-2025	Western		PJM RTO													
19-Feb-2025	Western				DOM_ASHBURN											
30-Mar-2025										PJM RTO						
16-Apr-2025							PJM RTO									
18-Apr-2025										PJM RTO						
19-Apr-2025										PJM RTO						
20-Apr-2025										PJM RTO						
26-Apr-2025										PJM RTO						
27-Apr-2025										PJM RTO						
11-May-2025										PJM RTO						
18-May-2025										Western						
24-May-2025										PJM RTO						
28-May-2025							PJM RTO									
01-Jun-2025							PJM RTO	COMED		PJM RTO						
02-Jun-2025							PJM RTO									
12-Jun-2025							PJM RTO									
18-Jun-2025													PJM RTO			
22-Jun-2025		PJM RTO														
23-Jun-2025					Mid-Atlantic except RECO, SMECo, SRE, UGI; Southern									PJM RTO		
24-Jun-2025					Mid-Atlantic except RECO, SMECo, SRE, UGI; Southern; Western except AMPT, CPP, ITCI, OVEC, WVPAT									PJM RTO		
25-Jun-2025					Mid-Atlantic except RECO, SMECo, SRE, UGI; Southern; FE-AP									PJM RTO		
26-Jun-2025		PJM RTO														
06-Jul-2025		Western except COMED, ITCI														
07-Jul-2025		Mid-Atlantic, Southern														
15-Jul-2025														PJM RTO		
16-Jul-2025														PJM RTO		
17-Jul-2025		Mid-Atlantic, Southern														
18-Jul-2025													PJM RTO			
23-Jul-2025		Western														
24-Jul-2025		PJM RTO												PJM RTO		
25-Jul-2025		PJM RTO												PJM RTO		
26-Jul-2025		Mid-Atlantic, Southern														
28-Jul-2025		PJM RTO			Southern, BGE, PEPCO									PJM RTO		
29-Jul-2025		PJM RTO			Mid-Atlantic except RECO, SMECo, SRE, UGI; Southern; Western except AMPT, CPP, ITCI, OVEC, WVPAT									PJM RTO		
30-Jul-2025		PJM RTO												PJM RTO		
06-Aug-2025													PJM RTO			
11-Aug-2025					BGE	BGE					BGE					BGE
12-Aug-2025		Mid-Atlantic														
17-Aug-2025		PJM RTO														
30-Aug-2025										PJM RTO						
31-Aug-2025										PJM RTO						
01-Sep-2025										PJM RTO						
07-Sep-2025										Western						
08-Sep-2025										Western						
14-Sep-2025							PJM RTO									
30-Sep-2025							PJM RTO									

Figure 3-51 Days with applicable alerts, actions, and recalls[122]: January 14 through January 25, 2025

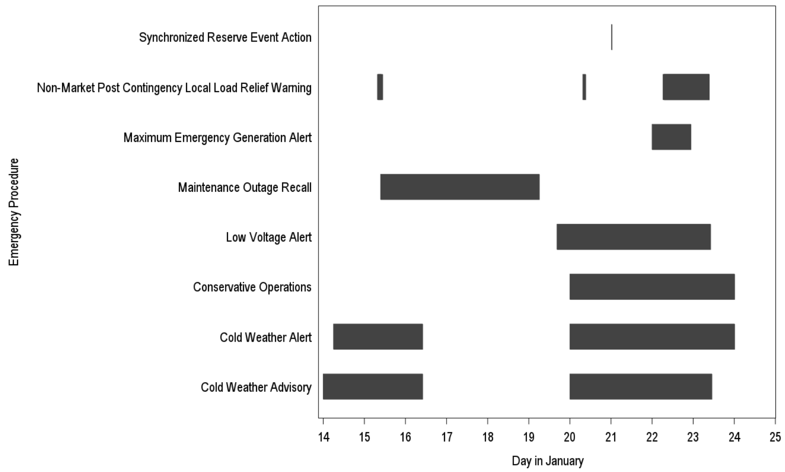
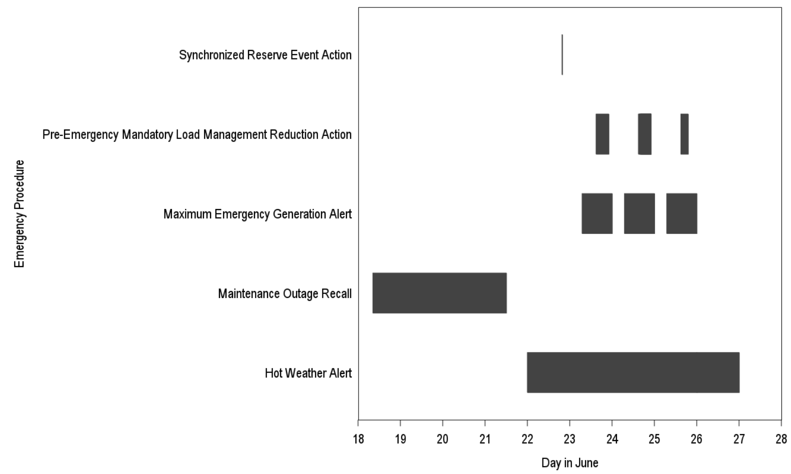


Figure 3-52 Days with applicable alerts, actions, and recalls: June 18 through June 27, 2025



122 To be consistent with other statistics in this section, the length of the maintenance outage recall has been reduced to the days starting from when the recall was issued until the time units were expected to be available. In the previous report, the recall was shown as lasting until near the end of the cold weather.

Figure 3-53 Days with applicable alerts, actions, and recalls[123]: July 14 through July 31, 2025

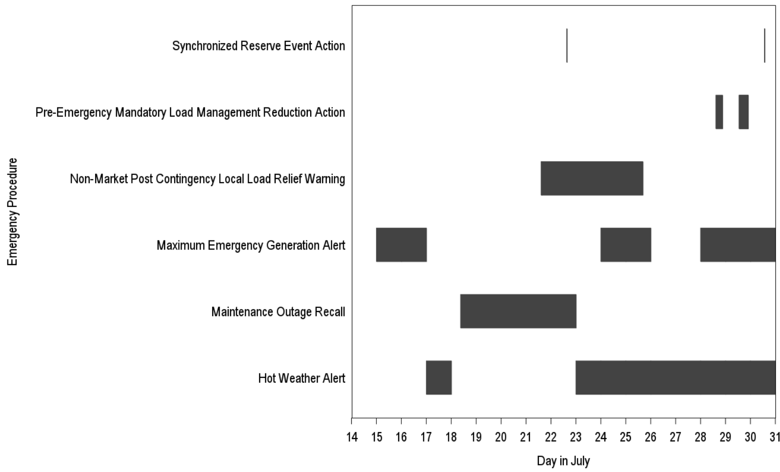


Table 3-81 shows the number of days for which emergency alerts, warnings, actions, and informational postings were declared by PJM in the first nine months of 2024 and the first nine months of 2025. In the first nine months of 2025, there were zero days with emergency actions and shortages that triggered Performance Assessment Intervals (PAI).[124] The voltage reduction action on August 11, 2025, did not trigger a PAI because the action was limited to the BGE region.[125]

Table 3-81 Number of days for which PJM declared events (alerts, warnings, actions, and certain informational postings)[126]: January through September, 2024 and 2025

	Number of days for which events declared	
Event Type	2024 (Jan-Sep)	2025 (Jan-Sep)
Cold Weather Alert	8	13
Conservative Operations	5	8
Emergency Mandatory Load Management Reduction Action	0	1
Geomagnetic Disturbance Action	2	1
Geomagnetic Disturbance Warning	15	13
High System Voltage Action	6	18
Hot Weather Alert	28	18
Load Shed Directive	0	1
Low Voltage Alert	0	5
Maintenance Outage Recall	7	28
Maximum Emergency Generation Alert	1	11
Pre-Emergency Mandatory Load Management Reduction Action	0	7
Voltage Reduction Action	0	1
Shortage Pricing	29	130
Energy export recalls from PJM capacity resources	0	0

123 To be consistent with other statistics in this section, the length of the maintenance outage recall has been reduced to the days starting from when the recall was issued until the time units were expected to be available. In the previous report, the recall was shown as lasting until near the end of the cold weather.
124 A PAI is triggered when PJM takes an emergency action and there is a shortage of primary reserves. See 184 FERC ¶ 61,058 (2023).
125 See "August 11 BGE Load Shed Event," PJM presentation to the Operating Committee. (September 11, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250911/20250911-item-04---bge-load-shed-event.pdf>

126 TLRs, Post Contingency Local Load Relief Warnings, and Non-Market Post Contingency Local Load Relief Warnings are excluded due to their high frequency.

Figure 3-54 shows the number of days for which emergency alerts were issued in PJM in the first nine months of 2021 through 2025.

Figure 3-54 Number of days for which emergency alerts declared: January through September, 2021 through 2025

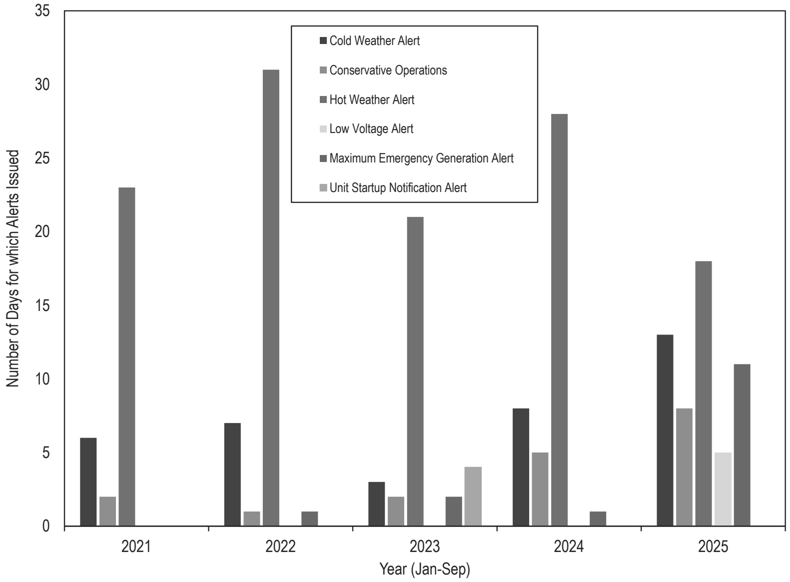


Figure 3-55 shows the number of days for which emergency warnings and actions were declared in PJM in the first nine months of 2021 through 2025.

Figure 3-55 Declared emergency warnings and actions: January through September, 2021 through 2025

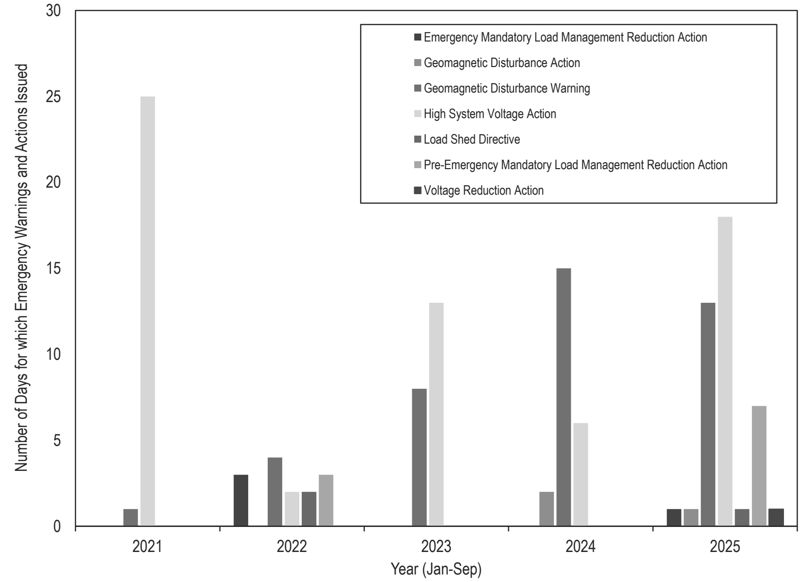


Figure 3-56 shows the number of local load relief warnings declared in PJM in the first nine months of 2025. Figure 3-57 shows the number of post-contingency local load relief warnings (PCLLRWs) affecting each area targeted by PCLLRWs. A single PCLLRW can be declared for multiple regions.

Figure 3-56 Declared local load relief warnings: January through September, 2025

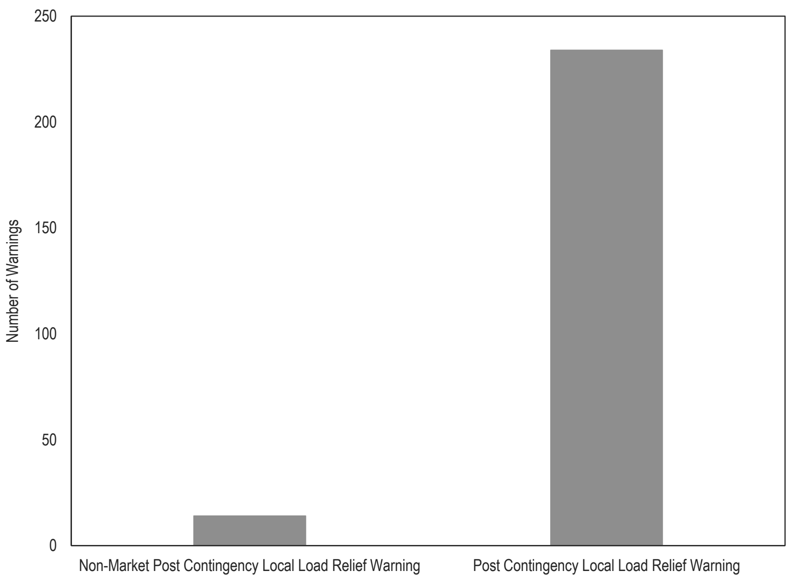
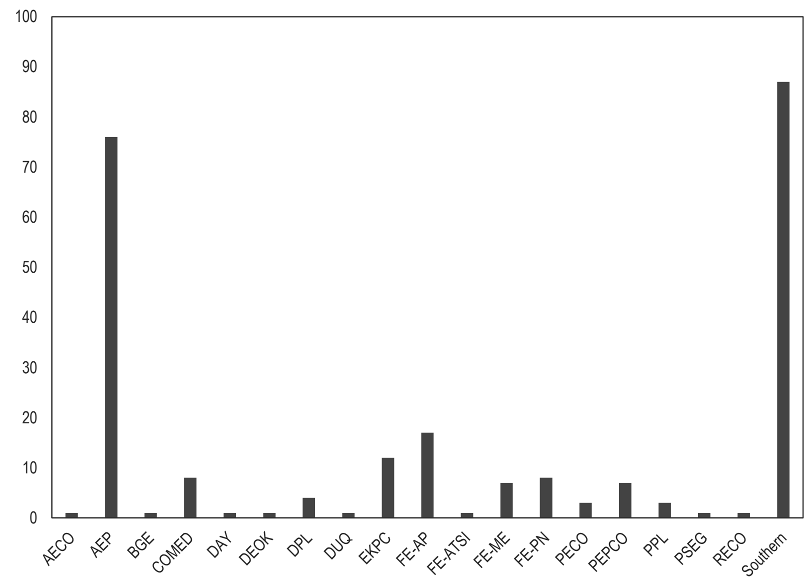


Figure 3-57 Number of post-contingency local load relief warnings affecting an area: January through September, 2025



Power Balance Constraint Violation

The purpose of the real-time energy market is to dispatch sufficient supply to meet demand. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand. In some cases, the power balance constraint is violated while the reserve requirements are satisfied.

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM converts reserves to energy before violating the power balance constraint. It is unclear whether and when PJM uses its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear why PJM does not include demand side capacity resources in the definition of reserves. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by the ASO to energy to satisfy the power balance constraint.[127] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the defined logic met transmission constraint limits and reserve requirements but violated the power balance constraint, and did not reflect this constraint violation in prices. The definitions and implementation of reserves, combined with operator discretion to bias load, make it difficult to define when there is an actual power balance constraint violation. Effective August 8, 2024, PJM updated SCED and LPC to convert reserves to energy before violating the power balance constraint.

During Winter Storm Elliott, on December 23, and December 24, 2022, PJM created what PJM termed virtual generation in real time to satisfy the power balance constraint. PJM did not convert any inflexible reserves to energy. In summary, the power balance constraint was violated solely as a result of load bias added by PJM and that violation was corrected by PJM adding generation that does not actually exist to the supply (virtual generation). To the extent that there was not an actual violation of the power balance constraint, it was appropriate that PJM did not take actions to address the nonexistent violation.

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should include: the exact definition of the power balance constraint including the role of PJM load bias; a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources to address any actual or potential power balance issue; a process to call on demand side capacity resources, and the minimum level of synchronized reserves that would trigger load shedding. Table 3-82 shows the number of five minute intervals for which the RT SCED solutions did not balance demand and supply. Prior to August 8, 2024, PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first nine months of 2025, there were six five-minute intervals that used an RT SCED solution with an apparently violated power balance constraint.

On June 24, 2025, PJM apparently violated the power balance constraint for two five minute intervals in the hour beginning at 1800 in the pricing run. In those two five minute intervals, PJM also capped the energy LMP at $3,700 per MWh. However, PJM positively biased the load forecast in the two intervals where the power balance constraint was violated.

Table 3-82 Number of five minute intervals using RT SCED solutions with apparently violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP in SCED ($/MWh)	Average Energy Component of LMP in Pricing Run ($/MWh)
2013	-	$0.00	$0.00
2014	655	$36.29	$36.29
2015	71	($0.76)	($0.76)
2016	42	$93.06	$93.06
2017	31	$279.86	$279.86
2018	16	$268.21	$268.21
2019	36	$845.48	$845.48
2020	5	$351.56	$351.56
2021	10	$976.06	$976.06
2022	121	$2,347.33	$2,066.21
2023	23	$357.34	$361.14
2024	6	$907.95	$907.95
2025 (Jan - Sep)	6	$3,542.96	$3,123.31

Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling scarcity conditions through higher energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power by individual generation owners for specific units when the system was close to its available capacity. That was not an efficient way to

127 Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

manage shortage pricing and made it difficult to distinguish between market power and shortage pricing. Shortage pricing is an administrative pricing mechanism that sets a defined higher price when the system operates with real-time reserves that are lower than the target level.

In the first nine months of 2025, there were 130 five-minute intervals with real-time shortage pricing for one or more reserve products that occurred on 22 days in PJM.

In Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[128] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. The implementation is not fully algorithmic or well defined because RT SCED can indicate a shortage that PJM does not use in pricing and because the load bias added to SCED may artificially create or suppress shortages. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to every five minutes in order to match the frequency of pricing in the LPC, which reduced the frequency of unpriced shortage solutions.

Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC.[129] This can lead to differences between the dispatched reserves in RT SCED and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing could be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution. This occurred for 19 intervals in the first nine months of 2025.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the power balance constraint is met and there is no defined shortage of reserves.[130]

Operating Reserve Demand Curves

Shortage pricing in the PJM Energy Market can occur in either the day-ahead or the real-time market for any of five reserve requirements: RTO Synchronized Reserves, Subzone Synchronized Reserves, RTO Primary Reserves, Subzone Primary Reserves, and 30-Minute Reserves. Each requirement is modelled in the market clearing engines as a demand curve priced at $850 per MWh up to the minimum reserve requirement (MRR) and at $300 per MWh for additional reserves of at least 190 MW.[131] [132] During reserve shortages, the prices on the demand curve are added to LMP. This is called shortage pricing. Mathematically, when a reserve constraint is not satisfied, the area under the demand curve for the unmet MW of the reserve requirement is added to the market clearing cost-minimization objective function as a penalty for violating a reserve constraint, which causes the administrative price on the ORDC to determine the marginal cost of the reserve shortage. This is why the values on the ORDC are sometimes called penalty factors. Because an additional MW of energy on the margin would require another MW of reserves shortage, the administrative marginal cost of reserves defined by the ORDC is added to LMP.

128 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).

129 *See* PJM Operating Agreement, Schedule 1, Section 2.5.1(a).

130 *See, e.g.*, Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21–30:14 (Oct. 28, 2014).

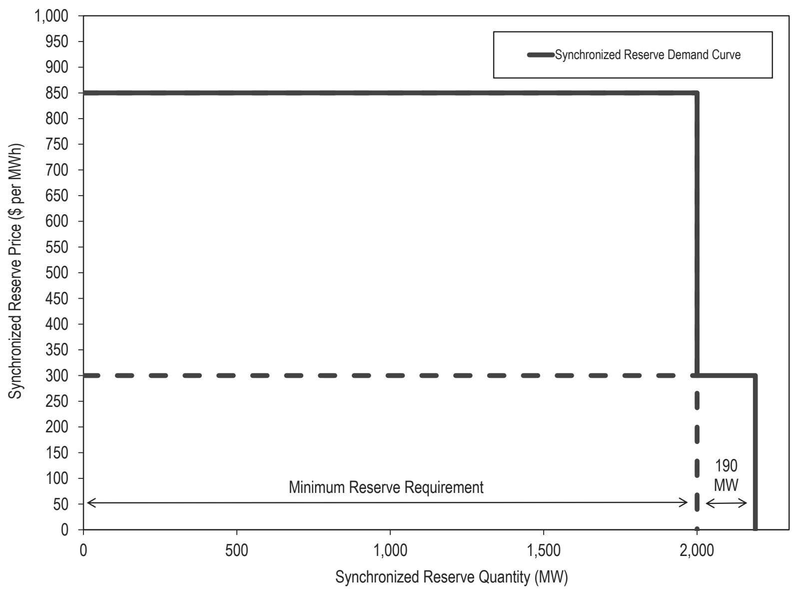
131 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.3 Reserve Demand Curves and Penalty Factors, Rev. 133 (Dec. 17, 2024).

132 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 133 (Dec. 17, 2024).

Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (synchronized, primary, and 30-minute reserves) up to the extended reserve requirement quantities, which for each reserve service is the sum of that service's minimum reserve requirement (MRR) and an extended requirement of at least 190 MW. The price is $850 per MWh for reserve quantities less than the MRR. The price is $300 per MWh for reserve quantities between the MRR and the sum of the MRR and the extended requirement. The example demand curve shown in Figure 3-58 drops to a zero price for quantities above the extended reserve requirement.

Figure 3-58 Example real-time extended synchronized reserve demand curve showing the permanent second step



Historically, the minimum reserve requirement for each operating interval has equaled the size of the largest single source of supply on the PJM system during that operating interval, known as the most severe single contingency. Beginning May 12, 2023, PJM unilaterally increased the minimum reserve requirement based on what appeared to be low response rates from reserves but not based on any evidence about reliability issues. The changes to the reserve requirements are discussed in more detail in Section 10: Ancillary Service Markets.

Nesting

The reserve requirements are nested such that the reserves with shorter allowed response times and stricter synchronization requirements count toward the requirements for reserves with longer allowed response times and less strict synchronization requirements, and such that the reserves in the subzone count toward the total RTO requirement. For example, synchronized reserves count toward the primary reserve requirement, and Mid-Atlantic Dominion reserves count toward the PJM RTO reserve requirement. This nesting means that the effect of reserve constraints on prices can be additive.

The effect of the reserve constraints on pricing depends on the constraint shadow price. The market uses constraints to ensure that reliability requirements are met while production costs are minimized. A binding constraint means that the market incurred some additional production cost to satisfy the constraint. A violated constraint has no associated production cost, so the market assigns an administrative cost based on the ORDC. The shadow price of a constraint is the change in the total production cost (the objective function of the market dispatch software) if that constraint limit were increased at the margin. A reserve constraint violation (a shortage) means that the constraint cannot be satisfied at a marginal cost less than the value on the ORDC. For the RTO synchronized reserve constraint, the shadow price during a shortage is defined to equal the ORDC value. For the MAD synchronized reserve constraint, when reserves from both the RTO and MAD can be used, the shadow price equals the sum of the ORDC value for each constraint when both are violated. The same occurs for the primary and secondary reserve constraints. The total shadow price of reserve violations can reach five times the highest ORDC value of

$850 per MWh, which is $4,250 per MWh. This value exceeds the PJM $1,700 per MWh price caps on reserve prices and the $3,700 per MWh price cap applied to the energy component of LMP, also called the system marginal price.

Energy and Reserve Price Caps

Table 3-83 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

Scenario A shows a simple shortage in the RTO Reserve Zone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a $1,700 per MWh reserve shortage penalty in the RTO Zone LMP and a $3,400 per MWh reserve shortage penalty in the MAD Zone LMP. The marginal resource for energy is in the RTO Zone. The RTO to MAD reserve transfer constraint is binding, so the higher MAD reserve penalty does not affect the rest of RTO LMP.

In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a violated transmission constraint that affects the marginal congestion costs in the system marginal price. In scenario C, the sum of the marginal unit cost, reserve and transmission constraint penalty factors equals $5,450 per MWh, which exceeds $3,700 per MWh, so SMP capping is triggered whether the marginal unit for energy can provide reserves for the MAD Zone or only the RTO Zone.

In scenario D, with a $1,000 per MWh offer price for the marginal unit for energy, violation of four reserve penalty factors does not trigger SMP capping, because the marginal unit for energy cannot serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed $3,700 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.[133]

In Scenario F, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for primary and synchronized reserves in both MAD and RTO Reserve Zones and a shortage of 30 minute reserves, resulting in a capped $1,700 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario F are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple violated transmission constraints, the congestion costs contributing to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh.

Scenarios G and H are similar to conditions during the highest priced hours of Winter Storm Elliott on December 23 and 24, 2022. In G, the marginal unit offer price is $500 per MWh. The synchronized and primary reserve requirements are violated for the RTO and MAD zones. Transmission constraints affect both the system marginal price and other locations. The SMP in G is capped at $3,700 per MWh. In H, the marginal unit offer price is lower, at $40 per MWh, and the 30 minute reserve constraint is also violated. With the offer caps, the SMP is also at $3,700 per MWh.

The extent to which each transmission penalty factor for a constraint affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint. In addition, the LMP at a pnode includes a loss component calculated as the product of the marginal loss factor and the uncapped system marginal price.

133 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

Table 3-83 Real-time additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

Scenario	Marginal Unit Offer Price	Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		30 Minute Reserve Penalty Factor	Transmission Constraint Penalty Factor in SMP	System Marginal Price		Transmission Constraint Penalty Factor in CLMP	Total LMP	
		RTO	MAD	RTO	MAD	RTO		RTO Marginal	MAD Marginal		RTO Marginal	MAD Marginal
A	$50	$850	$0	$0	$0	$0	$0	$900	$900	$0	$900	$900
B	$50	$850	$850	$850	$850	$0	$0	$1,750	$3,450	$0	$1,750	$3,450
C	$50	$850	$850	$850	$850	$0	$2,000	$3,700	$3,700	$0	$3,700	$3,700
D	$1,000	$850	$850	$850	$850	$0	$0	$2,700	$3,700	$0	$2,700	$3,700
E	$1,000	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
F	$2,000	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
G	$500	$850	$850	$850	$850	$0	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
H	$40	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700

Shortage Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. PJM's method of communication prior to December 2024 failed to result in reliably timely responses, defined to be within 10 minutes. For units that could receive an electronic signal, PJM's instruction to units supplying reserves was to ignore the dispatch signals sent by RT SCED and to instead ramp their units up until the spin event ends. A significant number of resources did not have the capability to receive the electronic signals that PJM offered. The ALL-CALL system only calls a limited number of contacts at the same time. Although PJM's stated goal was an immediate response, in practice it took minutes for a generator's designated contact to respond to the ALL-CALL, who could then take minutes more to call personnel at the plant. If a unit was following automatic generation control when an event was declared, then additional minutes could also be lost switching to manual control. The end result of these communications issues was that resources started responding only after minutes into an event, even when everything went well.[134] In December 2024, PJM added an automated communication method that would add the reserve deployment instruction to the dispatch signal, which will allow generators following automatic generation control to automatically follow the signal. The new method did not affect any synchronized reserve events in 2024. The new method applied to all 19 events in the first nine months of 2025, of which only four exceeded ten minutes. The new method did not resolve the communications issues for all resources. Significant communications issues remain unresolved.

Although PJM signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load and reserve requirements 8 to 10 minutes into the future. Currently, RT SCED has the ability to back down units during events to create available reserves, which counteracts PJM's recovery effort. This results in a discrepancy between the RT SCED solutions and the operational need during a spinning event. While PJM recovers from a disturbance during a spinning event, PJM should adjust the operating reserve demand curve (ORDC) for synchronized reserves to ensure that RT SCED does not have a competing objective of immediately replacing reserves that have been paid for and are being used as intended. Without such an adjustment, the prices will be artificially inflated, potentially triggering shortage pricing, during the times when reserves are used for their intended purpose. For example, nine shortage pricing intervals were artificially triggered during the spin events on February 5, February 11, June 22, August 14, September 4, and September 25, 2025. The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirements by the amount of the reserves deployed.

134 See the *2024 State of the Market Report for PJM*, Volume 2: Section 10: Ancillary Service Markets for a more detailed discussion of these issues.

Reserve Shortages in the First Nine Months of 2025

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the five minute target time RT SCED solutions indicated a shortage of any of the reserve products in the RTO Reserve Zone and the MAD Reserve Subzone (synchronized reserve and primary reserve in both areas and 30-minute reserve in the RTO), when multiple solutions indicated shortage of reserves, and how many of these resulted in shortage prices in LPC. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement. To trigger shortage pricing, PJM operators must approve an LPC case in which the MW of reserves in the pricing run of the LPC are short of the extended reserve requirement.

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[135] [136] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflect shortage pricing.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-84 shows, in 2024 and the first nine months of 2025, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which multiple RT SCED solutions showed a shortage of reserves, and the number of five-minute pricing intervals for which the LPC solution showed a shortage of reserves. Each execution of RT SCED produces five solutions, using five different levels of load bias. Table 3-84 shows that, in 2024, 6,811 target times, or 6.5 percent of all five-minute target times, had at least one RT SCED solution showing a shortage of reserves, and 1,905 target times, or 1.8 percent of all five-minute target times, had more than one RT SCED solution showing a shortage of reserves. In the first nine months of 2025, there were 4,082 target times, or 5.2 percent of all five-minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 1,368 target times, or 1.7 percent of all five-minute target times, that had multiple RT SCED solutions showing a shortage of reserves.

135 A case is executed when it begins to solve. Most but not all cases are solved. RT SCED cases take about one to two minutes to solve.
136 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020. PJM dispatchers may solve additional cases at their discretion.

Table 3-84 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2024 through September 2025

Year	Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2024	Jan	8,928	398	4.5%	119	1.3%	10	2.5%
2024	Feb	8,352	606	7.3%	156	1.9%	0	0.0%
2024	Mar	8,916	876	9.8%	259	2.9%	9	1.0%
2024	Apr	8,640	434	5.0%	103	1.2%	2	0.5%
2024	May	8,928	792	8.9%	249	2.8%	1	0.1%
2024	Jun	8,640	404	4.7%	115	1.3%	2	0.5%
2024	Jul	8,928	390	4.4%	118	1.3%	3	0.8%
2024	Aug	8,928	532	6.0%	119	1.3%	0	0.0%
2024	Sep	8,640	687	8.0%	223	2.6%	2	0.3%
2024	Oct	8,928	654	7.3%	205	2.3%	6	0.9%
2024	Nov	8,652	645	7.5%	157	1.8%	1	0.2%
2024	Dec	8,928	393	4.4%	82	0.9%	3	0.8%
2024	Total	105,408	6,811	6.5%	1,905	1.8%	39	0.6%
2025	Jan	8,928	248	2.8%	75	0.8%	0	0.0%
2025	Feb	8,064	379	4.7%	91	1.1%	3	0.8%
2025	Mar	8,916	653	7.3%	220	2.5%	11	1.7%
2025	Apr	8,640	630	7.3%	224	2.6%	3	0.5%
2025	May	8,928	595	6.7%	195	2.2%	2	0.3%
2025	Jun	8,640	360	4.2%	170	2.0%	79	21.9%
2025	Jul	8,928	384	4.3%	124	1.4%	16	4.2%
2025	Aug	8,928	365	4.1%	109	1.2%	7	1.9%
2025	Sep	8,640	468	5.4%	160	1.9%	9	1.9%
2025	Total	78,612	4,082	5.2%	1,368	1.7%	130	3.2%

As shown in Table 3-84, in 2024, there were 1,905 unique five-minute target times for which multiple RT SCED solutions showed a shortage of reserves for one or more reserve services, while there were 39 unique five-minute intervals with real-time shortage pricing for one or more reserve products. In the first nine months of 2025, there were 1,368 unique five-minute target times for which multiple RT SCED solutions showed a shortage of reserves for one or more reserve services, while there were 130 unique five minute intervals with real-time shortage pricing for one or more reserve products. Clear criteria for approval of shortage cases are needed.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions or implement shortage pricing when there are no shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases that are used to send dispatch signals to resources, and for pricing, to minimize discretion. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient.

Shortage Pricing Intervals in LPC

Beginning October 1, 2022, shortage pricing can occur in both the PJM Day-Ahead and Real-Time Energy Markets for Synchronized Reserves, Primary Reserves, and 30-Minute Reserves.

In May 2023, PJM increased reserve requirements in response to poor reserve performance by the units selected to provide reserves. PJM unilaterally increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the most severe single contingency (MSSC), which consequently increased the primary reserve reliability requirement by 45 percentage points to 195 percent of the MSSC. While the intervals listed in this section were short of their target requirements, many of these intervals still cleared above the average values of the requirements from before the increase.

The average primary reserve requirement from January 2023 through April 2023 was 2,511.4 MW and the average synchronized reserve requirement was 1,741.7 MW. Many of the intervals with shortage pricing were not short in the sense of failing to clear a sufficient amount of reserves for recovering from a contingency event. They were short because of PJM's unilateral increase to the synchronized reserve reliability requirement. Table 3-85 shows the count of intervals with shortage pricing for synchronized reserve (SR), primary reserve (PR), and 30-minute reserve (TMR). As seen in Table 3-85, the majority of intervals with shortage pricing cleared reserves in excess of the original reserve requirements absent PJM's adder.

Table 3-85 Number of shortage pricing intervals which satisfied the unmodified reserve service requirement: January through September, 2025

	Intervals with Shortage Pricing			Intervals where RT SCED Satisfied Original Requirement			Percentage of Intervals where RT SCED Satisfied Original Requirement			Intervals where RT SCED Did Not Satisfy Original Requirement		
Location	SR	PR	TMR	SR	PR	TMR	SR	PR	TMR	SR	PR	TMR
RTO	17	111	22	17	79	16	100.0%	71.2%	72.7%	0	32	6
MAD	6	6	0	4	2	0	66.7%	33.3%	NA	2	4	0

There were 130 unique real-time five minute intervals with shortage pricing for one or more reserve products in the first nine months of 2025, compared to 29 intervals in the first nine months of 2024. In the first nine months of 2025, there were 130 five minute intervals with shortage pricing in the pricing run for one or more reserve products, and there were 111 intervals with shortage in the dispatch run for one or more reserve products. The following tables show intervals with shortage pricing in the pricing run for each reserve service for the RTO Reserve Zone and the MAD Reserve Subzone. PJM implemented fast start pricing on September 1, 2021. Fast start pricing can result in differences in reserve shortages between the dispatch run and the pricing run.

In 2024, there were no hours with shortage pricing in the day-ahead reserve markets. In the first nine months of 2025, there were four unique day-ahead hours with shortage pricing for one or more reserve products. For February 25, in the day-ahead market, there was one hour with shortage pricing for primary reserves in the MAD Reserve Subzone. For July 29, in the day-ahead market, there were three hours with shortage pricing for primary reserves in the RTO Reserve Zone.

Table 3-86 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the 20 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2025. Table 3-86 shows that the 20 intervals were short of synchronized reserves in both the pricing run and the dispatch run. Seven intervals were also short of synchronized reserves in MAD in the pricing and dispatch run. Thirteen intervals were also short of primary reserves in the RTO in the pricing and dispatch runs. Nine intervals were also short of primary reserves in MAD in the pricing and dispatch runs. Seven intervals were also short of 30-minute reserves in the RTO in the pricing and dispatch runs. Six intervals overlapped with spinning events on February 5, February 11, June 22, 2025, and September 4, 2025.

Table 3-87 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Zone during the three intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2025. Table 3-87 shows that the three intervals were short of synchronized reserves in both the pricing run and the dispatch run. One interval was also short of primary reserves in the RTO in the pricing and dispatch run. Three intervals were also short of 30-minute reserves in the pricing and dispatch run. Five intervals occurred during synchronized reserve events and were also short of synchronized reserve in the RTO in the pricing and dispatch run.

Table 3-88 shows a summary of the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the 125 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2025. Of the 125 intervals that were short of primary reserves, 106 were short in both the pricing run and the dispatch run. Eight intervals were also short of primary reserve in the MAD Reserve Subzone in the pricing run and dispatch run. Thirteen intervals were also short of synchronized reserve in the RTO Reserve Zone in the dispatch run and pricing run. Five intervals were also short of synchronized reserve in the MAD Reserve Subzone in the dispatch run and pricing run. Twenty-three intervals were also short of 30-minute reserves in the RTO Reserve Zone in the dispatch run and pricing run. The one interval on February 11, two intervals on June 22, two intervals on August 14, one interval on September 4, and one interval on September 25 overlapped with synchronized reserve events.

Table 3-89 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the nine intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2025. Table 3-88 shows that all nine intervals were short of primary reserves in both the pricing run and the dispatch run. All nine intervals were also short of primary reserves in the RTO Reserve Zone in the pricing run and the dispatch run. All nine intervals were also short of synchronized reserve in the RTO Reserve Zone in the pricing run and the dispatch run. Four of the intervals were also short of synchronized reserve in the MAD Reserve Subzone in the pricing run and the dispatch run. The intervals on June 22 and September 4 overlapped with synchronized reserve events.

Table 3-90 shows the extended 30-minute reserve requirement, the total 30-minute reserves, the 30-minute reserve shortage, and the 30-minute reserve clearing prices for the RTO Reserve Zone during the 23 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2025. Table 3-88 shows that all 23 intervals were short of 30-minute reserves in both the pricing run and the dispatch run. All 23 intervals were also short of primary reserves in the RTO Reserve Zone in the pricing run and the dispatch run. Three intervals were also short of primary reserve in the MAD Reserve Subzone in the pricing run and the dispatch run. Six intervals were also short of synchronized reserve in the RTO Reserve Zone in the pricing run and the dispatch run. Three of the intervals were also short of synchronized reserve in the MAD Reserve Subzone in the pricing run and the dispatch run. The interval on June 22 occurred during a synchronized reserve event.

PJM enforces an RTO wide reserve requirement and a reserve requirement for the MAD region. The MAD Reserve Subzone is inside the RTO Reserve Zone. Resources located in the MAD Reserve Subzone can simultaneously satisfy the synchronized reserve requirement of the RTO Reserve Zone and the synchronized reserve requirement of the MAD Reserve Subzone. Resources located outside the MAD Reserve Subzone can satisfy the synchronized reserve requirement of the RTO Reserve Zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO Reserve Zone is set by the shadow price of the binding reserve requirement constraint of the RTO Reserve Zone.[137] The synchronized reserve clearing price of the MAD Reserve Subzone is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO Reserve Zone and the shadow price of the binding reserve requirement constraint of the MAD Reserve Subzone.

The process of calculating reserve constraint shadow prices and implementing reserve price caps in PJM is not transparent. The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including definitions of all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices.

The PJM tariff caps the MCP for primary reserves at one and a half times the nonsynchronized reserve penalty factor for each zone or subzone, and caps the MCP for synchronized reserves at the sum of the penalty factor for synchronized reserve and the penalty factor for nonsynchronized reserve, but the PJM tariff does not explicitly specify a cap on the system marginal price.[138] The system marginal penalty of $3,700 per MWh that is actually applied by PJM should be included in the PJM tariff and Operating Agreement.

137 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.
138 OA Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).

Table 3-86 Real-time RTO synchronized reserve shortage intervals: January through September, 2025

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)
05-Feb-25 10:05	1,947.0	1,754.6	192.4	$850.00	$850.00	1,947.0	1,754.6	192.4	$850.00	$850.00
05-Feb-25 10:10	1,945.1	1,687.0	258.1	$850.00	$850.00	1,945.1	1,687.0	258.1	$850.00	$850.00
11-Feb-25 09:05	1,952.5	1,854.1	98.5	$600.00	$600.00	1,952.5	1,854.1	98.5	$600.00	$600.00
15-Mar-25 10:25	2,515.1	2,492.9	22.2	$431.13	$431.13	2,515.1	2,492.9	22.2	$431.13	$431.13
15-Mar-25 10:30	2,515.1	2,492.9	22.2	$319.32	$319.32	2,515.1	2,492.9	22.2	$319.32	$319.32
08-Apr-25 07:00	1,920.3	1,720.9	199.4	$1,700.00	$1,700.00	1,920.3	1,720.9	199.4	$1,700.00	$1,700.00
08-Apr-25 07:05	1,920.3	1,530.8	389.5	$1,700.00	$1,700.00	1,920.3	1,530.8	389.5	$1,700.00	$1,700.00
08-Apr-25 07:10	1,920.3	1,720.2	200.1	$1,700.00	$1,700.00	1,920.3	1,720.2	200.1	$1,700.00	$1,700.00
22-Jun-25 19:35	2,515.1	2,325.1	190.0	$1,356.62	$1,356.62	2,515.1	2,325.1	190.0	$1,356.62	$1,356.62
22-Jun-25 19:40	2,515.1	2,055.1	459.9	$1,700.00	$1,700.00	2,515.1	2,055.1	459.9	$1,700.00	$1,700.00
22-Jun-25 19:45	2,515.1	2,055.1	459.9	$1,700.00	$1,700.00	2,515.1	2,055.1	459.9	$1,700.00	$1,700.00
23-Jun-25 20:15	2,515.1	2,406.7	108.3	$2,000.00	$1,700.00	2,515.1	2,406.7	108.3	$2,000.00	$2,000.00
23-Jun-25 20:20	2,515.1	2,309.9	205.2	$2,550.00	$1,700.00	2,515.1	2,309.9	205.2	$2,550.00	$2,550.00
23-Jun-25 20:25	2,515.1	2,435.2	79.8	$2,000.00	$1,700.00	2,515.1	2,435.2	79.8	$2,000.00	$2,000.00
24-Jun-25 11:55	2,515.1	2,416.1	98.9	$1,150.00	$1,150.00	2,515.1	2,416.1	98.9	$1,150.00	$1,150.00
24-Jun-25 18:50	2,515.1	1,619.0	896.1	$2,550.00	$1,700.00	2,515.1	1,619.0	896.1	$2,550.00	$2,550.00
24-Jun-25 18:55	2,515.1	1,615.0	900.1	$2,550.00	$1,700.00	2,515.1	1,615.0	900.1	$2,550.00	$2,550.00
24-Jun-25 19:00	2,515.1	1,668.2	846.9	$2,550.00	$1,700.00	2,515.1	1,668.2	846.9	$2,550.00	$2,550.00
30-Jun-25 12:45	2,515.1	2,325.1	190.0	$525.80	$525.80	2,515.1	2,325.1	190.0	$525.80	$525.80
04-Sep-25 20:00	2,515.1	1,861.7	653.4	$1,700.00	$1,700.00	2,515.1	1,861.7	653.4	$1,700.00	$1,700.00

Table 3-87 Real-time MAD synchronized reserve shortage intervals: January through September, 2025

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)
05-Feb-25 10:05	1,877.0	1,754.6	122.4	$1,150.00	$1,150.00	1,877.0	1,754.6	122.4	$1,150.00	$1,150.00
05-Feb-25 10:10	1,877.0	1,687.0	190.0	$1,651.36	$1,651.36	1,877.0	1,687.0	190.0	$1,651.36	$1,651.36
11-Feb-25 09:05	1,911.0	1,854.1	56.9	$900.00	$900.00	1,911.0	1,854.1	56.9	$900.00	$900.00
08-Apr-25 07:05	1,645.0	1,530.8	114.2	$2,850.00	$1,700.00	1,645.0	1,530.8	114.2	$2,850.00	$2,850.00
24-Jun-25 18:50	1,809.0	1,619.0	190.0	$4,155.70	$1,700.00	1,809.0	1,619.0	190.0	$4,155.71	$4,155.71
24-Jun-25 18:55	1,805.0	1,615.0	190.0	$3,700.00	$1,700.00	1,805.0	1,615.0	190.0	$3,700.00	$3,700.00
24-Jun-25 19:00	1,805.0	1,668.2	136.8	$3,700.00	$1,700.00	1,805.0	1,668.2	136.8	$3,700.00	$3,700.00

Table 3-88 Daily summary of real-time RTO primary reserve shortage intervals: January through September, 2025

		Pricing Run					Dispatch Run				
Day (EPT)	Intervals of Shortage	Average RTO Extended Primary Reserve Requirement (MW)	Average Total RTO Primary Reserves (MW)	Average RTO Primary Reserve Shortage (MW)	Average Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Average Capped RTO Primary Reserve Clearing Price ($/MWh)	Average RTO Extended Primary Reserve Requirement (MW)	Average Total RTO Primary Reserves (MW)	Average RTO Primary Reserve Shortage (MW)	Average Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Average Capped RTO Primary Reserve Clearing Price ($/MWh)
11-Feb-25	1	2,833.8	2,821.0	12.832	$300.00	$300.00	2,833.8	2,821.0	12.832	$300.00	$300.00
12-Mar-25	1	3,677.6	3,445.5	232.121	$850.00	$850.00	3,677.6	3,445.5	232.121	$850.00	$850.00
18-Mar-25	4	3,677.6	3,258.0	419.544	$850.00	$850.00	3,677.6	3,258.0	419.544	$850.00	$850.00
19-Mar-25	4	3,677.6	3,494.5	183.111	$575.00	$575.00	3,677.6	3,506.3	171.299	$575.00	$575.00
8-Apr-25	3	2,785.4	1,929.2	856.227	$850.00	$850.00	2,785.4	1,929.2	856.227	$850.00	$850.00
8-May-25	2	3,677.6	3,652.0	25.529	$300.00	$300.00	3,677.6	3,652.0	25.529	$300.00	$300.00
22-Jun-25	5	3,677.6	2,915.8	761.785	$850.00	$850.00	3,677.6	2,915.8	761.785	$850.00	$850.00
23-Jun-25	32	3,677.6	3,242.3	435.259	$989.50	$894.41	3,677.6	3,254.9	422.678	$958.19	$958.19
24-Jun-25	39	3,677.6	3,141.3	536.293	$894.21	$811.13	3,677.6	3,172.6	505.005	$869.31	$869.31
25-Jun-25	2	3,677.6	3,159.0	518.595	$850.00	$850.00	3,677.6	3,159.0	518.595	$850.00	$850.00
8-Jul-25	1	3,677.6	3,643.5	34.045	$300.00	$300.00	3,677.6	3,677.6	0.000	$170.92	$170.92
15-Jul-25	4	3,677.6	3,611.8	65.729	$300.00	$300.00	3,677.6	3,677.6	0.000	$289.55	$289.55
28-Jul-25	11	3,677.6	3,265.8	411.760	$537.29	$537.29	3,677.6	3,280.3	397.327	$497.52	$497.52
14-Aug-25	4	3,677.6	3,440.5	237.081	$551.91	$551.91	3,677.6	3,440.8	236.814	$551.91	$551.91
15-Aug-25	3	3,694.5	3,576.8	117.662	$483.33	$483.33	3,694.5	3,593.9	100.555	$474.25	$474.25
1-Sep-25	1	3,677.6	3,675.0	2.546	$300.00	$300.00	3,677.6	3,675.0	2.546	$300.00	$300.00
4-Sep-25	2	3,677.6	2,994.5	683.122	$850.00	$850.00	3,677.6	2,994.5	683.122	$850.00	$850.00
5-Sep-25	1	3,677.6	3,660.2	17.347	$300.00	$300.00	3,677.6	3,677.6	0.000	$290.05	$290.05
25-Sep-25	5	3,761.0	3,594.7	166.313	$630.00	$630.00	3,761.0	3,619.3	141.625	$624.87	$624.87

Table 3-89 Real-time MAD primary reserve shortage intervals: January through September, 2025

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)
08-Apr-25 07:00	2,372.5	1,992.9	379.7	$1,700.00	$1,275.00	2,372.5	1,992.9	379.7	$1,700.00	$1,700.00
08-Apr-25 07:05	2,372.5	1,802.7	569.8	$1,700.00	$1,275.00	2,372.5	1,802.7	569.8	$1,700.00	$1,700.00
08-Apr-25 07:10	2,372.5	1,992.2	380.4	$1,700.00	$1,275.00	2,372.5	1,992.2	380.4	$1,700.00	$1,700.00
22-Jun-25 19:40	2,627.5	2,526.7	100.8	$1,150.00	$1,150.00	2,627.5	2,526.7	100.8	$1,150.00	$1,150.00
22-Jun-25 19:45	2,627.5	2,526.7	100.8	$1,150.00	$1,150.00	2,627.5	2,526.7	100.8	$1,150.00	$1,150.00
24-Jun-25 18:50	2,618.5	1,621.4	997.1	$2,550.00	$1,275.00	2,618.5	1,621.4	997.1	$2,550.00	$2,550.00
24-Jun-25 18:55	2,612.5	1,617.4	995.1	$2,550.00	$1,275.00	2,612.5	1,617.4	995.1	$2,550.00	$2,550.00
24-Jun-25 19:00	2,612.5	1,670.6	941.9	$2,550.00	$1,275.00	2,612.5	1,670.6	941.9	$2,550.00	$2,550.00
04-Sep-25 20:00	2,681.5	2,576.4	105.0	$1,150.00	$1,150.00	2,681.5	2,576.4	105.0	$1,150.00	$1,150.00

Table 3-90 Real-time RTO 30-minute reserve shortage intervals: January through September, 2025

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended 30-Minute Reserve Requirement (MW)	Total RTO 30-Minute Reserves (MW)	RTO 30-Minute Reserve Shortage (MW)	Uncapped RTO 30-Minute Reserve Clearing Price ($/MWh)	Capped RTO 30-Minute Reserve Clearing Price ($/MWh)	RTO Extended 30-Minute Reserve Requirement (MW)	Total RTO 30-Minute Reserves (MW)	RTO 30-Minute Reserve Shortage (MW)	Uncapped RTO 30-Minute Reserve Clearing Price ($/MWh)	Capped RTO 30-Minute Reserve Clearing Price ($/MWh)
23-Jun-25 19:35	3,677.6	3,487.6	190.0	$617.80	$617.80	3,677.6	3,487.6	190.0	$617.80	$617.80
23-Jun-25 19:40	3,677.6	3,487.6	190.0	$692.22	$692.22	3,677.6	3,487.6	190.0	$692.22	$692.22
23-Jun-25 19:45	3,677.6	3,459.4	218.1	$850.00	$850.00	3,677.6	3,459.4	218.1	$850.00	$850.00
23-Jun-25 19:50	3,677.6	3,302.6	375.0	$850.00	$850.00	3,677.6	3,302.6	375.0	$850.00	$850.00
23-Jun-25 19:55	3,677.6	3,487.6	190.0	$676.49	$676.49	3,677.6	3,487.6	190.0	$676.49	$676.49
23-Jun-25 20:05	3,677.6	3,487.6	190.0	$380.81	$380.81	3,677.6	3,487.6	190.0	$380.81	$380.81
23-Jun-25 20:10	3,677.6	3,487.6	190.0	$631.19	$631.19	3,677.6	3,487.6	190.0	$631.19	$631.19
23-Jun-25 20:15	3,677.6	3,091.6	586.0	$850.00	$850.00	3,677.6	3,091.6	586.0	$850.00	$850.00
23-Jun-25 20:20	3,677.6	3,060.9	616.7	$850.00	$850.00	3,677.6	3,060.9	616.7	$850.00	$850.00
23-Jun-25 20:25	3,677.6	3,233.6	444.0	$850.00	$850.00	3,677.6	3,233.6	444.0	$850.00	$850.00
23-Jun-25 20:30	3,677.6	3,666.4	11.1	$300.00	$300.00	3,677.6	3,666.4	11.1	$300.00	$300.00
24-Jun-25 18:20	3,677.6	3,487.6	190.0	$375.98	$375.98	3,677.6	3,487.6	190.0	$375.98	$375.98
24-Jun-25 18:25	3,677.6	3,514.9	162.6	$300.00	$300.00	3,677.6	3,514.9	162.6	$300.00	$300.00
24-Jun-25 18:35	3,677.6	3,487.6	190.0	$544.68	$544.68	3,677.6	3,487.6	190.0	$544.68	$544.68
24-Jun-25 18:40	3,677.6	3,211.6	465.9	$850.00	$850.00	3,677.6	3,211.6	465.9	$850.00	$850.00
24-Jun-25 18:45	3,677.6	2,915.8	761.8	$850.00	$850.00	3,677.6	2,915.8	761.8	$850.00	$850.00
24-Jun-25 18:50	3,677.6	2,491.4	1,186.2	$850.00	$850.00	3,677.6	2,491.4	1,186.2	$850.00	$850.00
24-Jun-25 18:55	3,677.6	1,830.6	1,847.0	$850.00	$850.00	3,677.6	1,830.6	1,847.0	$850.00	$850.00
24-Jun-25 19:00	3,677.6	1,903.5	1,774.0	$850.00	$850.00	3,677.6	1,903.5	1,774.0	$850.00	$850.00
24-Jun-25 19:05	3,677.6	3,042.8	634.7	$850.00	$850.00	3,677.6	3,042.8	634.7	$850.00	$850.00
24-Jun-25 19:10	3,677.6	3,487.6	190.0	$650.74	$650.74	3,677.6	3,487.6	190.0	$650.74	$650.74
24-Jun-25 19:15	3,677.6	3,487.6	190.0	$639.86	$639.86	3,677.6	3,487.6	190.0	$639.86	$639.86
24-Jun-25 19:20	3,677.6	3,487.6	190.0	$554.92	$554.92	3,677.6	3,487.6	190.0	$554.92	$554.92

System Marginal Price Cap

Prior to PJM's implementation of the modified reserve markets on October 1, 2022, in the PJM real-time market, the SMP was capped at $3,750 per MWh. This cap was the sum of the Energy Offer Cap ($2,000 per MWh under defined conditions), the Synchronous Reserve Penalty Factor from the first step on the demand curve ($850 per MWh), the Primary Reserve Penalty Factor from the first step on the demand curve ($850 per MWh) and a threshold ($50 per MWh). The Operating Agreement stated that only two of the four reserve penalty factors may be applied.

In that prior implementation, if the SMP would otherwise exceed $3,750 per MWh, PJM solved the SCED optimization by progressively relaxing reserve requirement constraints until the SMP fell below the cap. For instance, if the original SMP was above $3,750, PJM would solve the SCED optimization by disabling the subzone (MAD) primary reserve requirement constraint. If the SMP from the relaxed SCED optimization was still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints. If the relaxed SCED optimization was still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints and the RTO primary reserve constraint.

Starting with PJM's implementation of the new Reserve Price Formation rules on October 1, 2022, in the PJM real-time market, the SMP has an administrative maximum price of $3,700 per MWh. Unlike the prior implementation, PJM's new cap does not include a $50 per MWh threshold and is not enforced by progressively relaxing reserve requirement constraints. PJM's new cap is an ex post administrative override of the SMP calculated in the pricing run (LPC). The SMP is not capped in the dispatch run (SCED). The congestion component of the LMP and the loss component of the LMP are not subject to this maximum price. The LMP at a pricing node could still exceed $3,700 per MWh. Unlike other administrative caps, such as the cap on the shadow price of a transmission constraint enforced through transmission penalty factor within the optimization, the SMP cap is not enforced within the optimization. When the SMP cap is enforced, the resulting LMPs are not consistent and do not accurately reflect the marginal cost of serving energy and reserves.

Table 3-91 shows the number of five minute intervals in the real-time market where the SMP was capped for each year since 2018. In the first nine months of 2025, there were four five minute intervals in the real-time market in which the SMP was capped.

Table 3-91 Number of five minute intervals with capped SMP: 2018 through September 2025

Year	Number of Five Minute Intervals with capped SMP
2018	0
2019	1
2020	1
2021	2
2022	51
2023	1
2024	0
2025 (Jan - Sep)	4

The MMU recommends that PJM stop capping the system marginal price and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh.

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[139] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that may result in generators underperforming their submitted ramp rates. PJM should address these

139 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

complexities through generator modeling improvements. PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

Generators can deselect themselves from providing reserves by communicating to PJM that their resources will not follow the dispatch signal (e.g. offer fixed gen or operate as nondispatchable). These actions allow generators to withhold reserves and result in a violation of the reserve must offer requirement when the resources operate below their economic maximum.

Competitive Assessment

Market Structure

Market Concentration

The Herfindahl-Hirschman Index (HHI) concentration ratio is the sum of the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the shares of the real-time energy output of generators, adjusted for scheduled imports. Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

The HHI is not a definitive measure of structural market power. It is possible to have pivotal suppliers even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of both local and aggregate structural market power than the HHI.

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. A pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is from 1000 to 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[140]

When transmission constraints exist, local markets are created in which ownership is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first nine months of 2025, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when PJM's flawed market power mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market in the first nine months of 2025 was unconcentrated on average (Table 3-92).[141] The fact that the average HHI and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

140 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).
141 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the owner that is responsible for offering the unit in the energy market.

Table 3-92 Real-time hourly aggregate energy market HHI: January through September, 2024 and 2025

HHI Statistic	Hourly Market HHI (Jan-Sep 2024)	Hourly Market HHI (Jan-Sep 2025)
Average	699	686
Minimum	553	511
Maximum	983	988
Highest market share (One hour)	26%	24%
Average of the highest hourly market share	18%	17%
# Hours	6,575	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-93 includes HHI values by supply curve segment, including base, intermediate and peaking plants in the first nine months of 2024 and 2025. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.[142]

Table 3-93 Real-time hourly energy market HHI by generation segment: January through September, 2024 and 2025

	Jan-Sep 2024			Jan-Sep 2025		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	573	727	1015	645	800	1101
Intermediate	438	1586	5992	424	912	2746
Peak	829	6293	10000	839	6616	10000

Figure 3-59 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2025.[143]

Figure 3-59 Real-time ICAP distribution by fuel and segment: January through September, 2025[144]

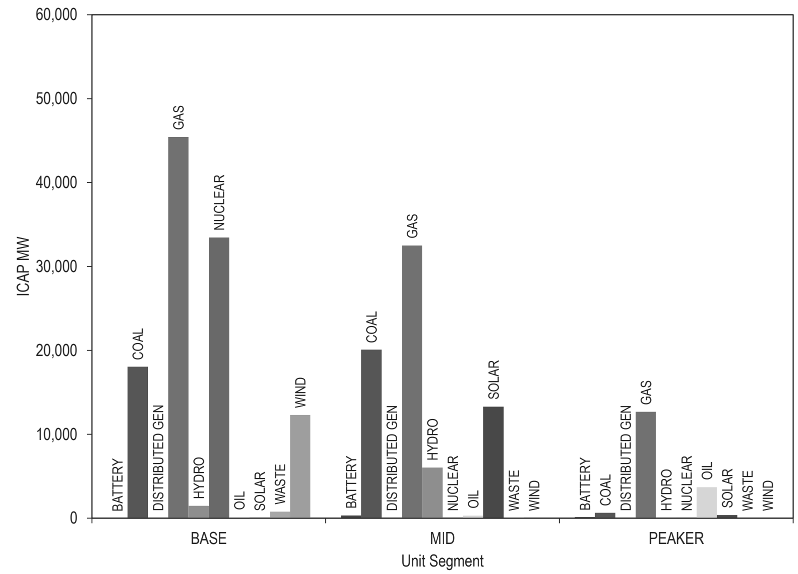


Figure 3-60 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from the first nine months of 2014 through 2025. Figure 3-60 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from the first nine months of 2014 through 2025, while the total ICAP of gas fired units in PJM classified as baseload generally increased. In 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time.

142 A unit is classified as base load if it runs for 50 percent of hours or more, as intermediate if it runs for less than 50 percent but greater than or equal to 10 percent of hours, and as peak if it runs for less than 10 percent of hours.
143 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their intermittent output characteristics.
144 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012).

Figure 3-60 Real-time annual gas and coal unit segment classification: January through September, 2014 through 2025

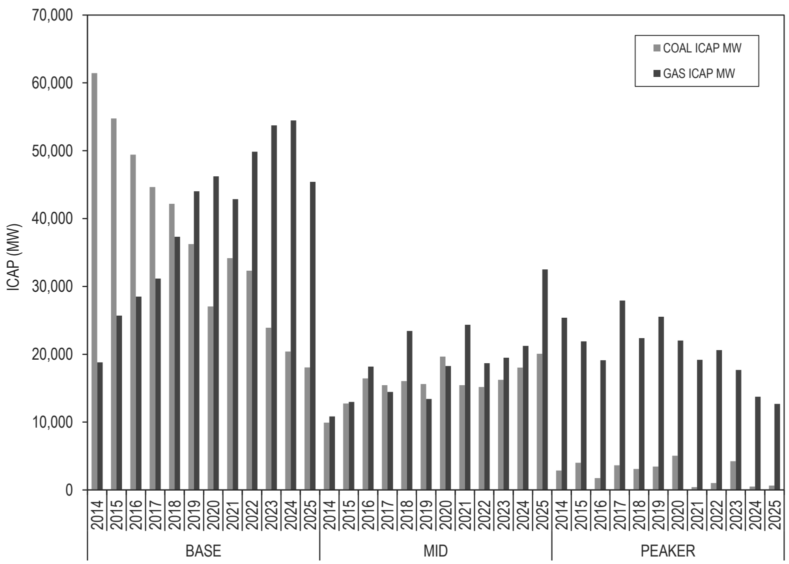


Figure 3-61 Real-time hourly aggregate energy market HHI: January through September, 2025

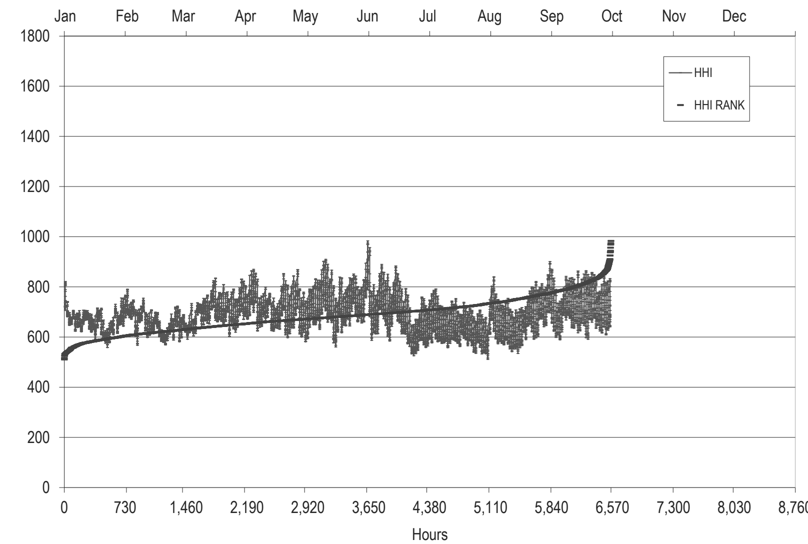


Figure 3-61 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2025.

Market Based Rates

Participation by generators in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[145] FERC reviews the market based rate authority of PJM market sellers of generation on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM region is included in the Northeast Region for purposes of the triennial review schedule. Triennial filings by utilities with market based rates authorizations must include a market power analysis or a statement that market power has been adequately mitigated under the PJM market rules. Based on Order No. 861, sellers may, in lieu of filing a market power analysis, rely on a rebuttable presumption

145 See *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 (2007), *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom.* Mont. Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011).

that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[146]

The rules specify a separate filing schedule for transmission owning utilities and nontransmission owning utilities. The rules define a study period for market power analyses including four complete seasons. A study runs from December of one year through November of the following year (i.e., the period includes one complete winter season rather than splitting winter as a calendar year approach would). The study period is not relevant for companies that choose the rebuttable presumption option.

The most recent triennial review filings for nontransmission owning utilities in PJM were filed in June 2023. The applicable study period for the June 2023 filings, ran from December 1, 2020, to November 30, 2021. Triennial review filings for transmission owners in PJM were filed in December 2022. The applicable study period for the December 2022 filings ran from December 1, 2020, to November 30, 2021.

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. With these results and the supporting evidence, the MMU challenged the rebuttable presumption of sufficient market power mitigation for the June 2020, December 2022, and June 2023 triennial review filings by generating unit owners in PJM. The MMU explained the issues with PJM's offer schedule selection process that allow generators to avoid energy market power mitigation as well as the then overstated capacity market seller offer cap. The MMU recommended that generators not be allowed to rely on PJM's implementation of market power mitigation rules to ensure competitive market outcomes until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[147] In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.[148] [149] FERC addressed the capacity market Market Seller Offer Cap later in 2021.[150] [151] FERC did not address the energy market power mitigation issues.

Merger Reviews

FERC reviews proposed dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[152] [153]

FERC applies tests set forth in the 1996 Merger Policy Statement, written prior to the introduction of competitive markets in PJM.[154] [155] The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. FERC continues to use the 1992 Guidelines even after the Department of Justice modified its guidelines in 2010.[156] Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates the results of a Competitive Analysis Screen measuring HHI changes for markets defined by transmission zones. This approach does not take into account the effect of a transaction on actual PJM LMPs or capacity market prices.

The MMU reviews proposed mergers and acquisitions based on analysis of the impact of the merger or acquisition on market power given actual PJM market

146 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019) ("Order No. 861").
147 See Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 et al. (August 28, 2020); Comments of the Independent Market Monitor for PJM, Docket No. ER10-1618-018 et al. (February 13, 2023); Comments of the Independent Market Monitor for PJM, Docket No. ER23-9-000 et al. (August 28, 2023).
148 See 175 FERC ¶ 61,231 (2021).
149 See 174 FERC ¶ 61,212 (2021).
150 See 176 FERC ¶ 61,137 (2021), *reh'g denied*, 178 FERC ¶ 61,121 (2022), *appeal denied*, Vistra Corp. v. FERC, 80 F.4th 302 (2023).
151 *See* Monitoring Analytics, L.L.C., *2021 Annual State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market at 311-312.
152 18 U.S.C. § 824b.
153 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)
154 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).
155 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.
156 See 138 FERC ¶ 61,109 (2012).

conditions under the current competitive market design. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments with FERC including such analyses.[157] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[158] Subsequent to the MMU's arguments about local markets, FERC has required further analysis of local markets from applicants at the transmission zone level.[159] FERC has considered the MMU's analysis in reviewing mergers but continues to apply an analysis that does not accurately account for locational market power in an LMP market.[160]

Neither the MMU's analysis nor the FERC defined analysis is an adequate replacement for effective market power mitigation, because system conditions are dynamic and any owner can become pivotal at any time. FERC routinely approves mergers and acquisitions and grants Market Based Rates authority to PJM market sellers despite known issues in the market power mitigation process that allow market sellers to exercise their market power. For this reason, the MMU recommends that FERC approve mergers and acquisitions conditioned on behavioral commitments by the market sellers that prevent the exercise of market power.

The MMU has also reached agreements to mitigate market power in cases where market power concerns have been identified.[161] [162] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of structural mitigation in the form of asset divestiture requirements.

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-94 shows ownership changes in the PJM market that involved entire resources that were completed in the first nine months of 2025, as reported to the Commission. Table 3-95 shows transactions that involved transfers of partial unit ownership that were completed in the first nine months of 2025, as reported to the Commission.[163]

157 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

158 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

159 See, for example, Darby Power, LLC, et al., Response to Second Deficiency Letter, Request for Confidential Treatment, Request for Shortened Comment Period, and Request for Expeditious Action, Docket No. EC24-125 (March 27, 2025).

160 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

161 See 138 FERC ¶ 61,167 at P 19 (2012). The Maryland PSC accepted without condition or modification the settlement between Constellation and the MMU at the February 1, 2022, hearing in Case No. 9271. See *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Order Approving 2021 Settlement Agreement and Denying Request to Require Exelon to Remain In PJM, Case No. 9271 (February 22, 2022). By its terms, the settlement became effective on February 1, 2022.

162 See 192 FERC ¶ 61,074 at 169. FERC accepted Constellation's behavioral commitments agreed to with the MMU and conditioned its approval of the acquisition of Calpine on those commitments.

163 The transaction completion date is based on the notices of consummation submitted to the Commission.

Table 3-94 Completed transfers of entire resources: January through September, 2025

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Albemarle Beach Solar, LLC	SE1 Holdings, LLC	True Green Capital Management, LLC	March 12, 2025	EC24-89
St. Joseph Energy Center, LLC	Ares Management Corporation	Wabash Valley Power Association, Inc. (50%) and Hoosier Energy Rural Electric Cooperative, Inc. (50%)	March 13, 2025	EC24-108
Altus Power, Inc.	Altus Power, Inc.	TPG, Inc.	April 16, 2025	EC25-57
Hill Top Energy Center LLC	Ares Management Corporation	Ardian US, LLC	April 23, 2025	EC25-34
Harts Mill Solar, LLC	Irradiant Partners, LP	Apollo Global Management, Inc	May 30, 2025	EC25-63
Dodson Creek Solar, LLC; Fayette Solar, LLC; Ross County Solar, LLC; Sycamore Creek Solar, LLC; Yellowbud Solar, LLC	National Grid, plc	Brookfield Corporation	May 29, 2025	EC25-64
Hummel Station, LLC and Rolling Hills Generating, L.L.C.	LS Power Development, LLC	Capital Power Corporation	June 9, 2025	EC25-79
Hillcrest Solar I, LLC	Innergex Renewable Energy Inc.	Caisse de dépôt et placement du Québec	July 21, 2025	EC25-69
Lightstone Marketing LLC (Darby Power, LLC; Gaving Power, LLC; Lawrenceburg Power, LLC; and Waterford Power, LLC)	Arclight Capital (50%) and Blackstone Inc. (50%)	Bridgepoint Group PLC	July 23, 2025	EC24-125
Potomac Energy Center	Ares Management Corporation	Blackstone Inc.	August 5, 2025	EC25-46
Camden Plant Holdings, LLC	Talen Energy Corporation	Partners Group AG	September 11, 2025	EC25-96
Red Oak Power, LLC	Morgan Stanley	Strategic Value Partners, LLC	September 12, 2025	EC25-115

Table 3-95 Completed transfers of partial ownership of resources: January through September, 2025

Generator or Generation Owner Name	Percent	From	To	Transaction Completion Date	Docket
Reworld Holding Corporation (Reworld Camden County, Reworld Delaware Valley, Reworld Essex, Reworld Plymouth, Reworld Union)	25.0%	EQT AB	GIC (Ventures) Pte. Ltd.	January 22, 2025	EC25-15
Heritage Public Utilities (Blossburg Power, Brunot Island Power, Gilbert Power, Hamilton Power, Hunterstown Power, Mountain Power, New Castle Power, Niles Power, Ortanna Power, Portland Power, Sayrebille Power, Shawnee Power, Shawville Power, Titus Power, Tolna Power, Warren Generation)	20.0%	J. Aron & Company LLC	Barclays Capital Inc.	January 14, 2025	EC25-23
Heritage Public Utilities (Blossburg Power, Brunot Island Power, Gilbert Power, Hamilton Power, Hunterstown Power, Mountain Power, New Castle Power, Niles Power, Ortanna Power, Portland Power, Sayrebille Power, Shawnee Power, Shawville Power, Titus Power, Tolna Power, Warren Generation)	<20%	Barclays Capital Inc.	XYQ Energy LP (<10%) and PGIM, INC (<10%)	February 20, 2025	EC25-25
Northwest Ohio Wind, LLC	50.0%	Grand River Wind, LLC	Arclight Capital	March 3, 2025	EC25-30
West Deptford Energy, LLC	57.7%	MC West Deptford Energy Investments, LLC (17.5%), ASRC Capital, LLC (11.58%), KPIC USA, LLC (17.5%), The Prudential Insurance Company of America (8.87%), The Lincoln National Life Insurance Company (2.22%)	LS Power Group	March 7, 2025	EC25-35
Birdsboro Power LLC	33.3%	Ares Management Corporation	Strategic Value Partners, LLC	May 1, 2025	EC25-56
Silicon Ranch Corporation (SR Turkey Creek, LLC)	10.2%	Shell plc, TD Bank, and Manulife Financial Corporation	AIP Management P/S	June 6, 2025	EC25-75
GenOn Holdings, Inc (Chalk Point Steam, LLC; Morgantown Power, LLC; Shawville Lessor Genco LLC)	16.0%	GenOn Holdings, Inc	Bank of America Corporation	July 2, 2025	EC25-65
West Deptfod Energy, LLC	14.5%	Ullico Inc.	LS Power Group	October 1, 2025	EC25-126

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is singly pivotal and has monopoly market power in the aggregate energy market. If reliably meeting the PJM system load requires energy from a small number of suppliers, those suppliers are jointly pivotal and have oligopoly market power in the aggregate energy market. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power. The identification of jointly pivotal suppliers as a source of market power does not require an assumption that the suppliers collude. There are multiple mechanisms that would permit the exercise of market power when there are limited suppliers providing relief to a constraint. FERC Order No. 697 also recognizes this explicitly in the discussion of HHI and pivotal suppliers.[164] FERC's definition of highly concentrated markets, based on an HHI greater than 1800, includes between five and six owners with equal market shares.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not generally correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[165] Aggregate market power should be mitigated in the PJM Day-Ahead and Real-Time Markets when the three pivotal supplier test for the aggregate market is failed.

Day-Ahead Aggregate Energy Market Pivotal Suppliers

To assess the number of pivotal suppliers in the aggregate day-ahead energy market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the day-ahead energy market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy. Generating units, import transactions, economic demand response, and INCs, are included for each supplier.[166] Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs, which is the total cleared supply for the peak hour of the day. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-62 shows the number of days in the first nine months of 2025 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers in the day-ahead aggregate energy market by daily peak load level. It shows that market power, measured by the average number of suppliers that are pivotal, increases with daily peak load. The average number of suppliers that were one of three pivotal suppliers (yellow line) was 65.1 on the 26 days with a peak load less than 90 GW (gray bar) and was 135.9 suppliers on the 30 days with a peak load between 120 and 130 GW. The number of pivotal suppliers generally increases with load. There were eight days with load greater than 150 GW. On two of those days, four suppliers were singly pivotal. On three of those days, five suppliers were singly pivotal. All suppliers that failed the three pivotal supplier screen failed the two pivotal supplier screen on all eight of those days.

164 Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 104–117.

165 One supplier, Exelon Generating Company, LLC, is partially mitigated for aggregate market power through a settlement agreement with the MMU filed December 30, 2021 and approved by the Maryland Public Service Commission as a condition of its merger. *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Maryland PSC Case No. 9271 (February 22, 2022). Order No. 90084 replaces the original 10 year settlement in this case included as a condition in Order No. 84698, issued February 17, 2012, which approved the merger between Exelon and Constellation Energy Group.

166 Generation, imports, demand response, and virtual transactions are assigned to parent companies based on the ultimate parent company owner of their PJM account.

Figure 3-62 Average number of pivotal suppliers in the day-ahead energy market by load level: January through September, 2025

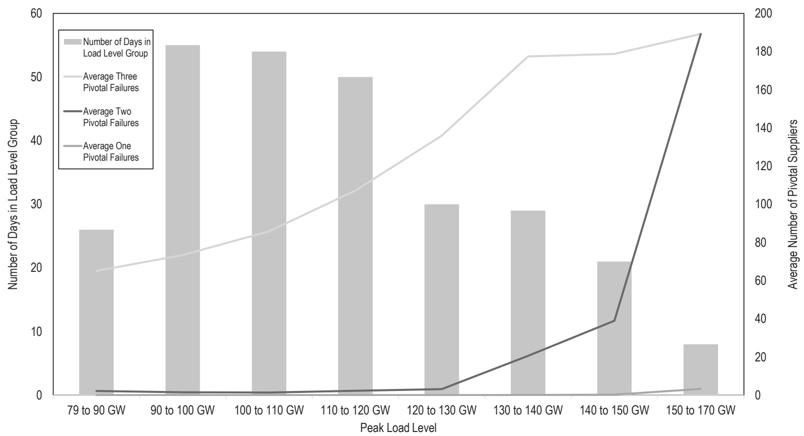


Table 3-96 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead aggregate energy market in the first nine months of 2025. All of the top 10 suppliers were one of three pivotal suppliers on at least 168 days in the first nine months of 2025 (61.5 percent of the days). One supplier was singly pivotal on 13 days.

Table 3-96 Day-ahead market pivotal supplier frequency: January through September, 2025

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	13	4.8%	145	53.1%	254	93.0%
2	6	2.2%	161	59.0%	257	94.1%
3	6	2.2%	131	48.0%	257	94.1%
4	5	1.8%	104	38.1%	251	91.9%
5	3	1.1%	86	31.5%	246	90.1%
6	0	0.0%	63	23.1%	223	81.7%
7	0	0.0%	36	13.2%	206	75.5%
8	0	0.0%	34	12.5%	173	63.4%
9	0	0.0%	31	11.4%	194	71.1%
10	0	0.0%	27	9.9%	168	61.5%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive.[167] If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[168] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based offers, also called price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

167 OA Schedule 1, Section 6.4.1.
168 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether three suppliers are jointly pivotal in a defined local market. The TPS test is applied when the system solution indicates that a transmission constraint is binding or requires the commitment of additional resources. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS test is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first nine months of 2025, in the day-ahead energy market, the 500 kV system, 19 of 21 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours, or resulting from a binding interface constraint (Table 3-97).[169] Table 3-97 shows that the 500 kV system, 13 of 20 zones and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from a binding interface constraint in the first nine months in every year from 2016 through 2025. DUKE and one zone did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in the first nine months in any year from 2016 through 2025.

Table 3-97 Day-ahead congestion hours resulting from one or more constraints binding for 75 or more hours: January through September, 2016 through 2025

	(Jan - Sep)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
500 kV System	4,822	6,301	3,681	4,544	4,741	1,896	2,014	971	1,361	1,341
ACEC	5,037	1,686	2,530	4,631	1,955	824	144	1,057	795	608
AEP	44,324	42,657	13,586	13,085	8,960	4,240	3,309	6,372	5,516	3,468
APS	9,508	9,206	2,382	2,153	3,204	2,442	1,223	1,508	1,855	1,680
ATSI	3,616	3,848	3,186	1,574	184	0	79	497	1,415	680
BGE	11,245	7,433	4,561	3,521	4,716	3,159	993	4,000	1,532	1,810
COMED	36,185	46,042	10,796	3,932	2,949	1,515	2,124	3,186	6,525	4,025
DAY	671	345	300	76	919	220	0	208	0	0
DEOK	7,658	5,820	2,393	1,124	218	517	485	583	324	281
DLCO	200	106	198	0	0	0	97	0	0	79
DOM	4,196	4,755	2,353	727	2,214	1,962	3,646	2,705	3,421	4,806
DPL	12,960	8,691	8,974	6,702	5,006	3,371	2,302	3,591	4,070	2,478
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	3,145	1,020	440	0	80	0	0	163	0	218
EXT	0	440	0	0	0	0	0	0	0	0
JCPLC	3,476	2,042	1,030	286	1,648	0	280	1,722	1,381	138
MEC	4,411	4,522	3,425	2,378	1,974	1,359	1,986	1,673	2,902	3,035
NYISO	0	515	0	0	0	0	0	0	0	0
OVEC	0	0	0	1,170	2,410	80	517	1,537	547	649
PE	8,606	17,758	7,485	2,739	3,256	681	3,216	3,829	6,373	7,957
PECO	5,115	8,840	2,643	1,218	917	1,333	3,349	4,404	3,408	2,635
PEPCO	276	643	116	79	0	0	228	364	354	640
PJM/MISO	17,250	18,558	14,699	7,450	4,514	4,334	7,949	4,742	3,782	6,941
PPL	2,175	6,095	3,193	7,328	4,142	3,942	4,707	2,252	2,755	3,017
PSEG	11,784	15,199	5,907	2,589	1,271	2,471	3,896	2,078	1,250	2,292
REC	0	0	326	1,074	182	1,069	723	895	287	0
TVA	223	0	0	206	75	0	0	0	0	0

In the first nine months of 2025, in the real-time energy market, the 500 kV system, 13 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours, or resulting from a binding interface constraint (Table 3-98).[170] Table 3-98 shows that the 500 kV system, six zones, and PJM/MISO experienced congestion resulting from one or more

169 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

170 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

constraints binding for 75 or more hours or resulting from a binding interface constraint in every year from 2016 through 2025. Three zones (DUQ, OVEC and REC), and DUKE did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in the first nine months in any year from 2016 through 2025.[171]

Table 3-98 Real-time congestion hours resulting from one or more constraints binding for 75 or more hours: January through September, 2016 through 2025

	(Jan - Sep)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
500 kV System	515	810	1,009	2,777	2,075	748	869	375	579	460
ACEC	413	0	94	97	0	0	0	0	0	0
AEP	441	469	1,170	381	887	976	311	534	1,130	878
APS	157	136	184	0	319	888	82	0	181	345
ATSI	0	133	814	0	0	0	78	78	1,015	87
BGE	4,227	1,297	2,144	533	2,040	1,374	495	1,993	804	856
COMED	2,588	913	522	78	856	762	865	600	2,787	2,093
DAY	0	0	0	0	0	181	0	0	0	0
DEOK	0	0	75	0	0	176	0	0	0	132
DOM	553	80	136	91	780	488	1,455	416	664	1,306
DPL	1,991	326	398	0	0	144	0	84	0	158
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	184	0	0	0	0	0	0	0
EXT	0	778	0	0	0	0	0	0	0	0
JCPLC	0	94	0	0	0	0	0	0	0	0
MEC	0	0	553	278	730	302	771	190	587	656
NYISO	730	332	0	0	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0
PE	141	1,541	1,114	1,013	1,950	586	1,522	2,144	3,818	4,505
PECO	657	1,312	537	224	284	612	2,134	2,552	1,468	1,417
PEPCO	0	0	0	0	0	0	0	0	77	83
PJM/MISO	2,983	3,797	3,060	3,035	2,453	2,458	6,015	3,431	3,494	3,850
PPL	242	563	0	748	460	751	1,582	91	96	477
PSEG	170	160	211	164	0	759	330	0	0	0
REC	0	0	0	0	0	0	0	0	0	0

171 In this report, the MMU used the dispatch run marginal resource and sensitivity factor data, rather than the pricing run data, in the analysis of constraints since 2021 because the PJM pricing run sensitivity factor data for day-ahead LMP was not correct for a small number of hours. The PJM pricing run LMPs are the final settlement LMPs.

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-99 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing the TPS test for the interface constraints in the PJM Day-Ahead Energy Market.

Table 3-99 Day-ahead three pivotal supplier test details for internal interface constraints: January through September, 2025

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	29	501	378	24	3	20
	Off Peak	60	458	1,156	37	24	13
AP South	Peak	117	579	1,072	33	19	14
	Off Peak	27	355	958	30	17	13
BCPEP	Peak	21	524	485	18	2	16
	Off Peak	0	0	0	0	0	0
Bedington - Black Oak	Peak	33	158	216	29	13	15
	Off Peak	21	174	335	33	26	7
Central	Peak	13	1,233	1,236	31	2	29
	Off Peak	0	0	0	0	0	0
West	Peak	19	758	1,189	32	11	21
	Off Peak	0	0	0	0	0	0

Table 3-100 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market, whether the TPS test was applied, and the average number of owners passing and failing the TPS test for the 10 constraints that were binding for the most hours in the day-ahead energy market. In the day-ahead energy market, the TPS test evaluates each constraint that was binding for each hour during the operating day after the initial unit commitment run. The set of constraints that are binding in the unit commitment run, for which the TPS test is applied, is not necessarily the same as the set of constraints that bind in the final day-ahead energy market solution. This is because PJM's day-ahead market is solved in three stages, and the initial set of constraints is from the Resource Scheduling and Commitment (RSC) (unit commitment) stage while the final set of binding constraints is from the Scheduling Pricing and Dispatch (SPD) (unit dispatch) stage.[172] The PJM approach fails to apply the TPS test to market sellers that provide relief to constraints in the final dispatch solution, and therefore fails to mitigate such sellers for market power.

The MMU recommends that PJM modify the process for applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers.

Table 3-100 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through September, 2025

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Lenox - North Meshoppen	Peak	1,017	79	46	8	1	6
	Off Peak	1,347	67	37	8	1	7
Nottingham	Peak	918	239	331	29	14	15
	Off Peak	667	174	362	27	18	9
Dune Acres - Michigan City	Peak	234	90	54	13	1	12
	Off Peak	691	109	111	18	2	16
Bergen - Hudson	Peak	3	14	33	1	0	1
	Off Peak	2	13	33	1	0	1
Graceton - Manor	Peak	270	303	279	30	8	22
	Off Peak	333	209	274	26	9	17
Haumesser Road - Steward	Peak	472	211	195	10	1	9
	Off Peak	397	177	162	9	1	8
Kewanee	Peak	397	88	74	5	0	5
	Off Peak	338	79	77	5	1	4
Pleasant View - Ashburn	Peak	170	193	149	25	7	18
	Off Peak	52	104	147	23	10	12
Easton - Emuni	Peak	88	360	18	2	0	2
	Off Peak	147	297	29	3	0	3
Carlisle Pike - Gardners	Peak	383	260	26	5	0	5
	Off Peak	180	119	14	4	0	4

172 *See* PJM. "Manual 11: Energy & Ancillary Services Market Operations," Section 5.2.6, Rev. 136 (Oct. 1, 2025).

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results for the first nine months of 2025.[173] While the real-time constraint hours include constraints that were binding in the five minute real-time dispatch solution (RT SCED), IT SCED, the software that performs the TPS test, may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times.[174] IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. Some IT SCED TPS solutions are used to commit units, while others are not. PJM operators have discretion in choosing which units to commit and which IT SCED results to use as the basis for the commitment and therefore which units are tested for market power using the TPS test. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that did result in offer capping.

Table 3-101 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the interface constraints in the PJM Real-Time Energy Market. Table 3-102 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-101 and Table 3-102 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look

173 See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

174 Prior to September 1, 2021, the real-time binding constraints were identical in the dispatch (RT SCED) and pricing (LPC) solutions. Beginning September 1, 2021, with implementation of fast start pricing, the set of binding constraints can differ between RT SCED and LPC pricing solutions. The set of constraints reported here are based on the binding constraints in RT SCED. This is because PJM commits and mitigates units based on a dispatch solution in IT SCED without fast start pricing.

ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

Table 3-101 Real-time three pivotal supplier test details for internal interface constraints: January through September, 2025

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	2,668	600	564	12	0	12
	Off Peak	3,299	588	644	13	0	13
AP South	Peak	2,284	415	437	13	2	11
	Off Peak	966	395	372	10	1	9
Bedington - Black Oak	Peak	1,073	194	195	14	4	10
	Off Peak	687	188	178	13	4	9

Table 3-102 Real-time three pivotal supplier test details for top 10 congested constraints: January through September, 2025

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Lenox - North Meshoppen	Peak	60,729	25	26	2	0	2
	Off Peak	82,640	22	25	2	0	2
Nottingham	Peak	25,254	135	129	11	2	9
	Off Peak	22,985	119	133	11	2	8
Dune Acres - Michigan City	Peak	8,204	34	35	4	0	3
	Off Peak	15,363	31	36	4	0	4
Kewanee	Peak	6,727	20	125	1	0	1
	Off Peak	6,851	18	94	1	0	1
Graceton - Manor	Peak	9,505	137	154	13	3	10
	Off Peak	13,554	116	139	12	2	10
Jordan - West Frankfort	Peak	3,162	46	19	3	0	3
	Off Peak	5,751	52	24	3	0	3
Prest - Tibb	Peak	1,579	31	14	3	0	3
	Off Peak	3,594	25	13	3	0	3
Dresden	Peak	9,740	30	33	2	0	2
	Off Peak	5,391	22	44	2	0	2
Haumesser Road - Steward	Peak	6,813	35	111	2	0	2
	Off Peak	7,010	35	110	2	0	2
Chapparal - Carson	Peak	7,377	55	114	2	0	2
	Off Peak	3,330	57	109	3	0	3

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[175] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, online units whose commitment is extended beyond the day-ahead or real-time commitment, and whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. Day-ahead committed units are not evaluated for offer capping in real-time unless they update their cost-based offer. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-103 shows that, in the first nine months of 2025, 4.6 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-103 shows that 7.8 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

175 If a steam unit were to lower its cost-based offer in real time, it would become eligible for offer capping based on the online TPS test.

Table 3-103 Day-ahead units committed on price-based offers that cleared real-time: January through September, 2024 and 2025

	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
Year (Jan-Sep)	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2024	89,947	2,294,967	199,788	3.9%	8.7%
2025	106,325	2,431,227	191,273	4.6%	7.8%

The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market.

Table 3-104 and Table 3-105 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping in the real-time energy market. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

Table 3-104 Summary of real-time three pivotal supplier tests applied for internal interface constraints: January through September, 2025

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AEP - DOM	Peak	2,668	2,661	100%	69	3%	3%
	Off Peak	3,299	3,293	100%	185	6%	6%
AP South	Peak	2,284	2,282	100%	67	3%	3%
	Off Peak	966	960	99%	18	2%	2%
Bedington - Black Oak	Peak	1,073	1,061	99%	17	2%	2%
	Off Peak	687	687	100%	23	3%	3%

Table 3-105 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: January through September, 2025

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Lenox - North Meshoppen	Peak	60,729	20,348	34%	2	0%	0%
	Off Peak	82,640	14,275	17%	7	0%	0%
Nottingham	Peak	25,254	24,780	98%	307	1%	1%
	Off Peak	22,985	22,757	99%	253	1%	1%
Dune Acres - Michigan City	Peak	8,204	657	8%	0	0%	0%
	Off Peak	15,363	2,330	15%	0	0%	0%
Kewanee	Peak	6,727	7	0%	0	0%	0%
	Off Peak	6,851	6	0%	0	0%	0%
Graceton - Manor	Peak	9,505	9,247	97%	116	1%	1%
	Off Peak	13,554	13,117	97%	191	1%	1%
Jordan - West Frankfort	Peak	3,162	0	0%	0	0%	0%
	Off Peak	5,751	0	0%	0	0%	0%
Prest - Tibb	Peak	1,579	0	0%	0	0%	0%
	Off Peak	3,594	0	0%	0	0%	0%
Dresden	Peak	9,740	1,383	14%	9	0%	1%
	Off Peak	5,391	547	10%	14	0%	3%
Haumesser Road - Steward	Peak	6,813	32	0%	0	0%	0%
	Off Peak	7,010	66	1%	6	0%	9%
Chapparal - Carson	Peak	7,377	4,971	67%	5	0%	0%
	Off Peak	3,330	2,631	79%	15	0%	1%

Offer Capping for Local Market Power

In the PJM energy market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons, like voltage support and N-2 contingencies, for providing black start and for providing reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

There are some issues with the application of mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. There are also issues with the absence of a TPS test under some conditions. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the day-ahead energy market and the real-time energy market. There is no tariff or manual language that defines the PJM process for evaluating units for multi-day commitments in the day-ahead energy market.

In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. The day-ahead energy market selects which schedule to use for a resource that failed the TPS test based on its objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period.

In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[176]

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

The hourly dispatch cost is calculated only at the economic minimum level and not at higher output levels. Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. This strategy is called crossing curves, or markup switching. Figure 3-63 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

176 See OA Schedule 1 § 6.4.1(g).

Figure 3-63 Offers with varying markups at different MW output levels

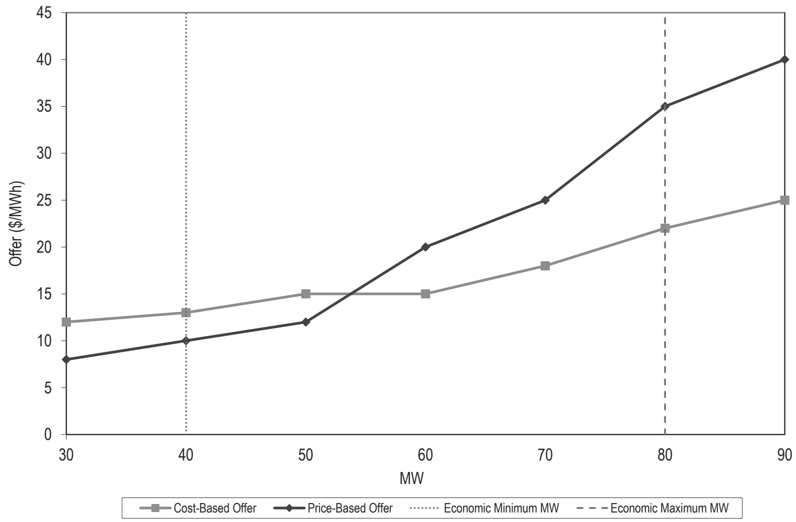


Table 3-106 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves (markup switch) in the PJM Day-Ahead and Real-Time Energy Markets in the first nine months of 2025. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, but they may elect to offer price-based offers.

Table 3-106 Units offered with crossing curves (markup switch): January through September, 2025

	Day-Ahead			Real-Time		
2025	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	81,057	889,896	9.1%	70,170	825,887	8.5%
Feb	78,904	807,696	9.8%	66,806	743,801	9.0%
Mar	81,963	891,245	9.2%	57,807	771,283	7.5%
Apr	78,129	866,880	9.0%	53,377	689,439	7.7%
May	85,949	897,984	9.6%	65,180	769,981	8.5%
Jun	88,261	858,504	10.3%	77,316	794,672	9.7%
Jul	98,474	889,848	11.1%	86,845	832,949	10.4%
Aug	96,152	890,040	10.8%	81,782	827,888	9.9%
Sep	91,581	866,904	10.6%	75,843	768,015	9.9%
Total	780,470	7,858,997	9.9%	635,126	7,023,915	9.0%

Table 3-107 shows the percent of unit schedule hours offered with crossing curves (markup switch), their average markup, their MW output weighted markup, and their average marginal unit LMP and markup contribution, when units failed the three pivotal supplier test in the PJM Day-Ahead Market and were marginal in the Real-Time Energy Market in the first nine months of 2025. The analysis only includes units that offer both price-based and cost-based offers.

Table 3-107 Marginal units offered with crossing curves (markup switch) and local market power: January through September, 2022 through 2025

Unit hours with Crossing Curves Committed on Price Offer and Eligible for Offer-Capping DA and Marginal in Real-Time							
Year (Jan-Sep)	Percent of Unit hours with Crossing Curves	Average Markup Day-Ahead	Average Markup Real-Time	Load-Weighted Average Markup Day-Ahead	Load-Weighted Average Markup Real-Time	Average Marginal Unit LMP Contribution	Average Marginal Unit Markup Contribution
2022	12.7%	$14.40	$8.26	$17.21	$12.60	$3.45	$0.47
2023	12.1%	$10.24	$3.23	$11.71	$5.25	$1.37	$0.17
2024	12.3%	$9.27	$3.34	$10.61	$5.54	$1.32	$0.14
2025	18.2%	$11.46	$9.17	$14.46	$13.66	$1.68	$0.27

Table 3-108 shows the percent of unit schedule hours offered with crossing curves (markup switch), their average markup, their MW output weighted markup, and their average marginal unit LMP and markup contribution, when units failed the three pivotal supplier test in the PJM Day-Ahead Market, were marginal in the Real-Time Energy Market and had a negative markup in the PJM Day-Ahead Market in the first nine months of 2025. The analysis only includes units that offer both price-based and cost-based offers.

Table 3-108 Marginal units offered with crossing curves (markup switch), local market power and negative markup day-ahead: January through September, 2022 through 2025

Unit hours with Crossing Curves Committed on Price Offer with Negative Markup and Eligible for Offer-Capping DA and Marginal with Positive Markup in Real-Time							
Year (Jan-Sep)	Percent of Unit hours with Crossing Curves	Average Markup Day-Ahead	Average Markup Real-Time	Load-Weighted Average Markup Day-Ahead	Load-Weighted Average Markup Real-Time	Average Marginal Unit LMP Contribution	Average Marginal Unit Markup Contribution
2022	2.0%	($8.20)	$20.83	($7.89)	$25.20	$3.73	$0.77
2023	2.7%	($3.16)	$10.54	($2.90)	$12.19	$1.22	$0.24
2024	2.6%	($3.48)	$11.37	($3.03)	$13.04	$1.47	$0.42
2025	3.7%	($3.98)	$23.24	($2.74)	$30.97	$1.69	$0.38

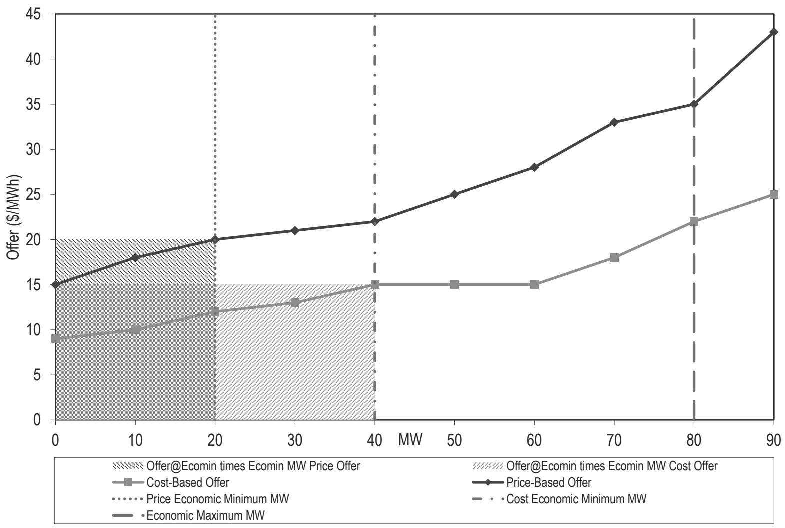
Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may have a price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-109 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-109 Units offered with lower minimum run time on price compared to cost and with positive markup: January through September, 2025

	Day-Ahead			Real-Time		
2025	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	2,733	889,896	0.3%	2,424	825,887	0.3%
Feb	2,634	807,696	0.3%	2,769	743,801	0.4%
Mar	10,697	891,245	1.2%	2,411	771,283	0.3%
Apr	5,914	866,880	0.7%	2,342	689,439	0.3%
May	4,752	897,984	0.5%	1,731	769,981	0.2%
Jun	1,704	858,504	0.2%	2,292	794,672	0.3%
Jul	2,148	889,848	0.2%	2,097	832,949	0.3%
Aug	2,395	890,040	0.3%	2,400	827,888	0.3%
Sep	2,256	866,904	0.3%	2,256	768,015	0.3%
Total	35,233	7,858,997	0.4%	20,722	7,023,915	0.3%

A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to the cost-based offer. Figure 3-64 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer solely as a result of the lower economic minimum MW. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-64 Offers with a positive markup but different economic minimum MW



The behavior in which units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer is limited to a number of units that does not permit data to be provided under the PJM confidentiality rules in both the day-ahead and real-time energy markets.

In the case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be cheaper even when it includes a markup. Figure 3-65 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup. Table 3-110 shows the number and percent of dual fuel unit hours where the price-based offer does not have a comparable cost-based offer with a matching fuel, and the cost-based offer exceeds the price-based offer. The analysis includes only those units that offered multiple offers (cost or price) with different fuels in the first nine months of 2025.

Figure 3-65 Dual fuel unit offers

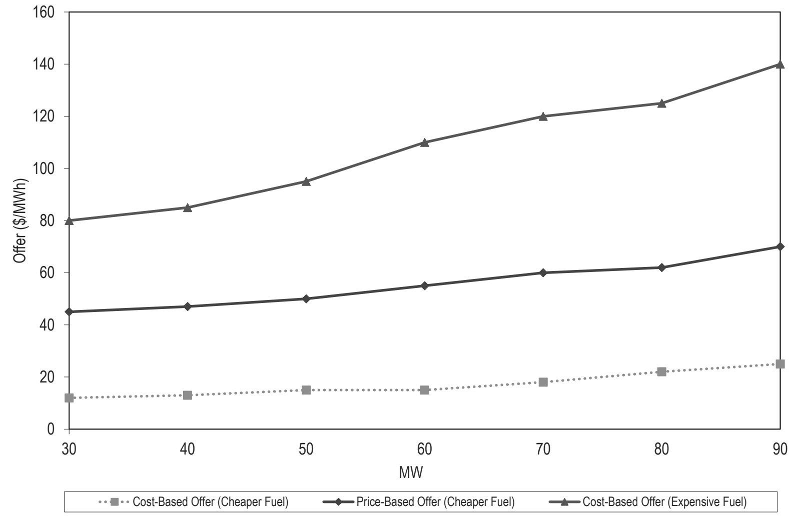


Table 3-110 Dual fuel unit offers with cost-based offers exceeding price-based offers (negative markup) but different fuel: January through September, 2025

	Day-Ahead			Real-Time		
2025	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost
Jan	6,173	204,096	3.0%	6,173	202,973	3.0%
Feb	7,185	187,416	3.8%	7,185	182,810	3.9%
Mar	4,447	208,474	2.1%	4,447	184,434	2.4%
Apr	10,077	196,488	5.1%	10,077	160,603	6.3%
May	9,642	203,280	4.7%	9,642	184,120	5.2%
Jun	12,369	194,568	6.4%	12,369	183,501	6.7%
Jul	14,535	206,472	7.0%	14,535	197,708	7.4%
Aug	14,927	204,216	7.3%	14,927	196,591	7.6%
Sep	11,465	193,488	5.9%	11,465	178,980	6.4%
Total	90,820	1,798,498	5.0%	90,820	1,671,720	5.4%

These issues can be solved by simple rule changes.[177] The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. This means that the cost-based and price-based offer curves never cross.[178]

PJM filed and, on October 25, 2024, FERC accepted a revised proposal that would require that sellers that fail the TPS test will be offer capped at their cost-based offers and that operating parameters will be mitigated. However, PJM has no plans to implement the improved rules, so the flawed rules remain in place. PJM's proposal also uses the flawed formula rejected by FERC to select among cost-based offers. This will result in the illogical selection of cost-based offers in some circumstances, particularly if a dual fuel unit submits offers for both oil and gas on a day when the economics change between the two fuels midday. PJM should modify its implementation to address that issue. The result would allow market sellers to select the correct cost-based fuel schedule. There is no reason to delay implementation until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The new approach should be implemented as soon as possible to help ensure effective market power mitigation.

The issues with offer capping will continue to allow the exercise of market power to affect prices until PJM implements the new approach. Currently, there is no implementation date. The simplified schedule selection process would shorten the time required to reach the day-ahead market solution, which is a market efficiency gain regardless of whether PJM implements combined cycle modelling. The MMU recommends that PJM commit all resources that fail the TPS test on their cost-based offers and that PJM implement that solution as soon as possible.[179]

Levels of offer capping have historically been low in PJM, as shown in Table 3-112. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November

177 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

178 See related recommendations about mitigation of operating parameters and financial offer parameters.

179 See "Schedule Selection: IMM Package," MMU Presentation to the Market Implementation Committee (September 6, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>.

1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[180] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer by PJM.

The offer capping percentages shown in Table 3-111 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, but excluding units that were committed for reliability reasons, providing black start or providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[181] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update.

Table 3-111 Offer capping statistics – energy only: January through September, 2018 to 2025

	Real-Time		Day-Ahead	
Year (Jan - Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.1%	0.5%	0.1%	0.2%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.4%
2021	1.3%	1.0%	1.4%	0.8%
2022	1.4%	1.1%	1.4%	1.0%
2023	1.3%	1.0%	1.6%	0.7%
2024	1.5%	1.0%	2.0%	1.0%
2025	1.4%	1.1%	1.9%	1.0%

Table 3-112 shows the offer capping percentages including both units committed to provide constraint relief and units committed for reliability reasons, black start or reactive support. Reliability reasons include reactive support or local voltage support. PJM creates closed loop interfaces to, in some cases, model reactive constraints. The closed loop interface creates demand for the output of the resource needed to provide reactive power. The resulting higher LMPs in the closed loop interfaces increased economic dispatch, which contributed to the reduction in units offer capped for reactive support over time in Table 3-113. In instances where units are committed and offer capped for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief, and not for reliability. They are included in the offer capping percentages in Table 3-111. Prior to closed loop interfaces, these units were considered as committed for reactive support, and were included in the offer capping statistics for reliability in Table 3-113.

Table 3-112 Offer capping statistics for energy and reliability: January through September, 2018 to 2025

	Real-Time		Day-Ahead	
Year (Jan - Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.2%	0.8%	0.2%	0.4%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.4%
2021	1.3%	1.0%	1.4%	0.8%
2022	1.5%	1.4%	1.5%	1.1%
2023	1.4%	1.2%	1.8%	1.0%
2024	1.7%	1.4%	2.2%	1.4%
2025	1.5%	1.3%	2.1%	1.2%

Table 3-113 shows the offer capping percentages only for units committed for reliability reasons, black start or reactive support. The low offer capping percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power, and all are treated consistent with that fact.[182]

180 See OA Schedule 1 § 6.4.1.
181 Prior to the *2018 Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.
182 OA Schedule 1, Section 6.4.1.

Table 3-113 Offer capping statistics for reliability: January through September, 2018 to 2025

	Real-Time		Day-Ahead	
Year (Jan - Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	0.14%	0.29%	0.12%	0.23%
2019	0.01%	0.02%	0.01%	0.01%
2020	0.00%	0.01%	0.00%	0.00%
2021	0.02%	0.04%	0.02%	0.02%
2022	0.15%	0.27%	0.06%	0.12%
2023	0.13%	0.23%	0.17%	0.27%
2024	0.18%	0.38%	0.23%	0.42%
2025	0.10%	0.23%	0.12%	0.24%

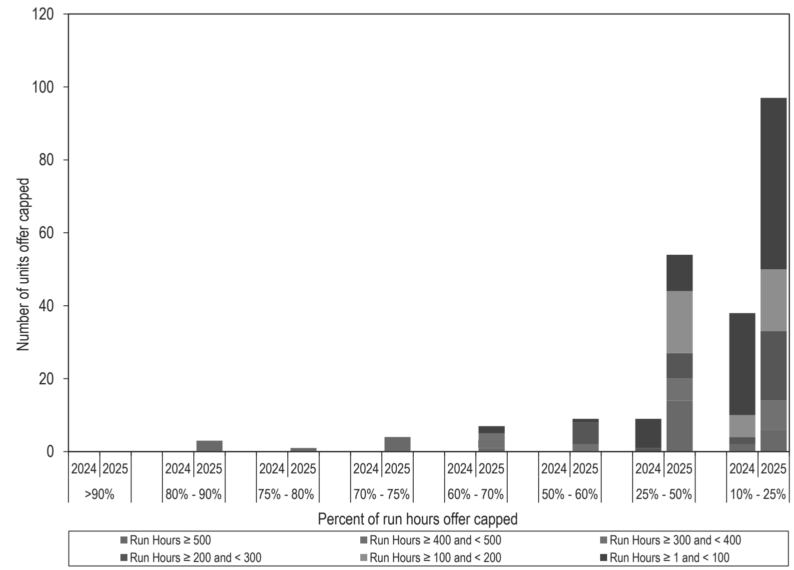
Table 3-114 presents data on the frequency with which units were offer capped in the first nine months of 2024 and 2025 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market, or for reliability reasons.

Table 3-114 Real-time offer capped unit statistics: January through September, 2024 and 2025

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Sep	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
	2024	0	0	0	0	0	0
90%	2025	0	0	0	0	0	0
	2024	0	0	0	0	0	0
80% and < 90%	2025	3	0	0	0	0	0
	2024	0	0	0	0	0	0
75% and < 80%	2025	1	0	0	0	0	0
	2024	0	0	0	0	0	0
70% and < 75%	2025	4	0	0	0	0	0
	2024	0	0	0	0	0	0
60% and < 70%	2025	1	2	2	0	0	2
	2024	0	0	0	0	0	0
50% and < 60%	2025	0	0	2	6	0	1
	2024	0	0	0	1	0	8
25% and < 50%	2025	14	0	6	7	17	10
	2024	2	0	0	2	6	28
10% and < 25%	2025	6	0	8	19	17	47

Figure 3-66 shows the frequency with which units were offer capped in the first nine months of 2024 and 2025 for failing the TPS test to provide energy for constraint relief in the real-time energy market or for reliability reasons.

Figure 3-66 Real-time offer capped unit statistics: January through September, 2024 and 2025



In response to FERC's request for Common Metrics for 2019 through 2022, which were published in FERC's 2023 Common Metrics Staff report, PJM filed a report stating that between 2019 and 2022 the percent of unit hours in the day-ahead energy market with active market power mitigation was between 78.8 and 100 percent, while the actual results were between 1.4 and 1.6 percent.[183] [184] PJM also reported that between 2019 and 2022, the percent of unit intervals in the real-time energy market with active market power mitigation was between 43.3 and 53.3 percent, while the actual results were

183 See Common Performance Metrics, Docket No. AD19-16-000, PJM Compliance Filing, PJM Metrics Spreadsheet 2023 (April 17, 2023).
184 See 2023 Common Metrics: Performance Metrics for ISOs, RTOs, and Regions Outside ISOs and RTOs for the Reporting Period 2019 to 2022, FERC Staff Report (January 31, 2024), <https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20240131-4000>.

between 1.0 and 1.7 percent. PJM's reported results were incorrect because PJM provided hours of mitigation instead of unit hours or unit intervals mitigated. In the day-ahead market, a mitigated unit hour is one unit mitigated for one hour. The denominator is all cleared units cleared for all hours. In the real-time market, a mitigated unit interval is one unit mitigated for one interval. The denominator is all cleared units for all intervals. For example, if there were 10 units running in a given hour in the day-ahead market, if one unit was mitigated for that hour, then the percent of unit hours mitigated would be 10 percent, but PJM defined the percent mitigated as 100 percent of the hour. The PJM filed report dramatically overstated the frequency of market power mitigation in the PJM energy market. The MMU has correctly reported this metric in the State of the Market Reports for 2002 and subsequent years. The MMU also reports the MWh subject to market power mitigation, which reflects the relative size of the units subject to market power mitigation.

Markup Index

Markup is a summary measure of the degree to which a participant's offer behavior or conduct for individual units is competitive. When a seller makes a competitive offer, markup is zero. When a seller exercises market power in its offer, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[185] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-115 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-116 shows the average markup index of marginal units in the real-time energy market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer at the dispatch point on the offer curves. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[186] The markup is negative if the cost-based offer of the marginal unit is greater than its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

PJM implemented Fast Start Pricing on September 1, 2021. For all the fast start marginal units beginning on September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer, and markup in the amortized no load offer.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. The PJM Market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[187]

185 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

186 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

187 See PJM. "Manual 15: Cost Development Guidelines," Rev. 47 (Oct. 1, 2025).

In the first nine months of 2025, the average dollar markup of units with offer prices less than $10 was negative (-$5.20 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was negative (-$2.32 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2025, 2.9 percent had offer prices above $150 per MWh. Among the units that were marginal in the first nine months of 2024, 1.4 percent had offer prices greater than $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2025 was more than $900, and the highest markup in the first nine months of 2024 was more than $900.

Table 3-115 Real-time average marginal unit markup index (By offer price category unadjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.14)	($1.50)	29.2%	(0.28)	($5.20)	17.0%
$10 to $15	(0.10)	($1.81)	18.3%	(0.13)	($2.32)	6.3%
$15 to $20	(0.10)	($2.92)	14.8%	(0.09)	($2.15)	13.8%
$20 to $25	(0.05)	($2.77)	12.0%	(0.07)	($2.11)	16.1%
$25 to $50	0.03	($1.89)	19.2%	(0.03)	($2.49)	34.3%
$50 to $75	0.14	$7.04	3.5%	0.05	$0.30	6.6%
$75 to $100	0.21	$14.90	0.9%	0.14	$11.09	1.7%
$100 to $125	0.32	$33.71	0.4%	0.19	$19.92	0.7%
$125 to $150	0.25	$35.26	0.2%	0.16	$20.36	0.5%
>= $150	0.12	$25.64	1.4%	0.07	$17.99	2.9%
All Offers	(0.06)	($0.93)	100.0%	(0.07)	($1.53)	100.0%

Table 3-117 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[188]

Table 3-116 Real-time average marginal unit markup index (By offer price category adjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.10)	($1.02)	29.2%	(0.28)	($4.81)	17.0%
$10 to $15	(0.03)	($0.73)	18.3%	(0.06)	($1.14)	6.3%
$15 to $20	(0.04)	($1.56)	14.8%	(0.02)	($0.54)	13.8%
$20 to $25	0.01	($1.10)	12.0%	0.00	($0.16)	16.1%
$25 to $50	0.09	$0.53	19.2%	0.04	$0.38	34.3%
$50 to $75	0.19	$10.33	3.5%	0.11	$4.60	6.6%
$75 to $100	0.25	$19.20	0.9%	0.20	$16.11	1.7%
$100 to $125	0.35	$37.06	0.4%	0.24	$25.40	0.7%
$125 to $150	0.28	$39.03	0.2%	0.21	$27.37	0.5%
>= $150	0.18	$40.86	1.4%	0.14	$37.34	2.9%
All Offers	(0.00)	$0.67	100.0%	(0.01)	$1.14	100.0%

Table 3-118 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In the first nine months of 2025, using unadjusted cost-based offers for coal units, 47.89 percent of marginal coal units had negative markups. The share of marginal coal units with negative markups at the dispatch point on their offer curve decreased from 60.08 percent in the first nine months of 2024 to 47.89 percent in the first nine months of 2025 when using unadjusted cost based offers.

Table 3-117 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	60.08%	27.04%	12.88%	47.89%	32.05%	20.06%
Gas	63.26%	16.78%	19.95%	65.47%	18.42%	16.11%
Oil	10.26%	88.05%	1.69%	16.44%	80.80%	2.76%

In the first nine months of 2025, using adjusted cost-based offers for coal units, 33.82 percent of marginal coal units had negative markups.

188 Other fuel types were excluded based on data confidentiality rules.

Table 3-118 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	49.81%	9.42%	40.77%	33.82%	8.79%	57.40%
Gas	45.03%	10.93%	44.04%	33.17%	11.11%	55.72%
Oil	9.85%	87.50%	2.64%	15.51%	79.59%	4.90%

Figure 3-67 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2024 and the first nine months of 2025 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[189] Of the gas units offered in the PJM market in the first nine months of 2025, 18.2 percent of gas unit hours had a maximum markup that was negative and 23.6 percent of gas fired unit hours had a maximum markup above $100 per MWh. The share of offered gas units with maximum markup that was negative decreased in the first nine months of 2025 compared to the first nine months of 2024, while the share of marginal gas units with negative markups at the dispatch point increased.

Figure 3-67 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2024 and 2025

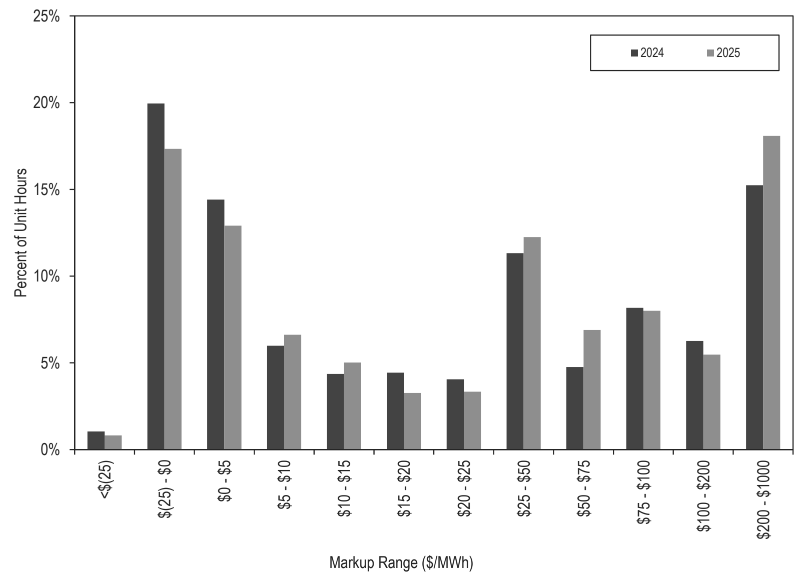


Figure 3-68 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2024 and the first nine months of 2025 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2025, 36.3 percent of coal unit hours had a maximum markup that was negative or equal to zero, increasing from 34.0 percent in the first nine months of 2024. The share of offered coal units with maximum markup that was negative increased in the first nine months of 2025, while the share of marginal coal units with negative markups at the dispatch point decreased in the first nine months of 2025 compared to the first nine months of 2024.

189 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-68 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2024 and 2025

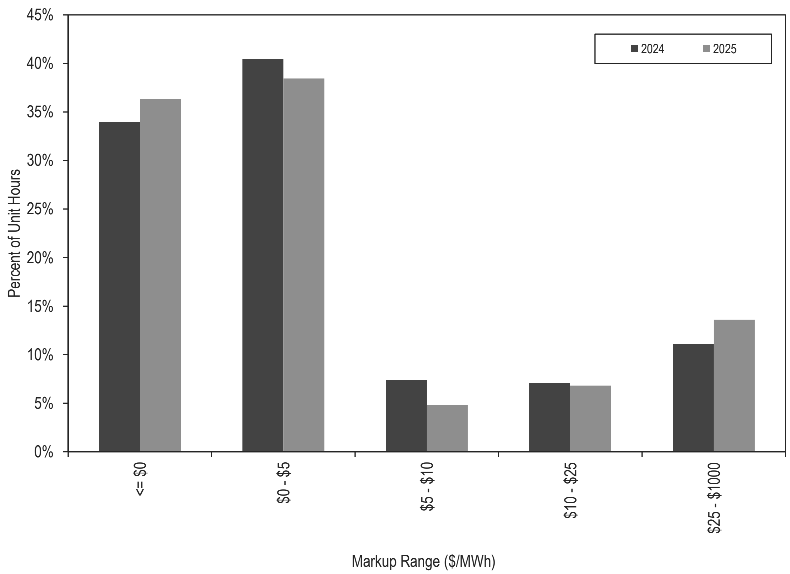


Figure 3-69 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2024 and 2025

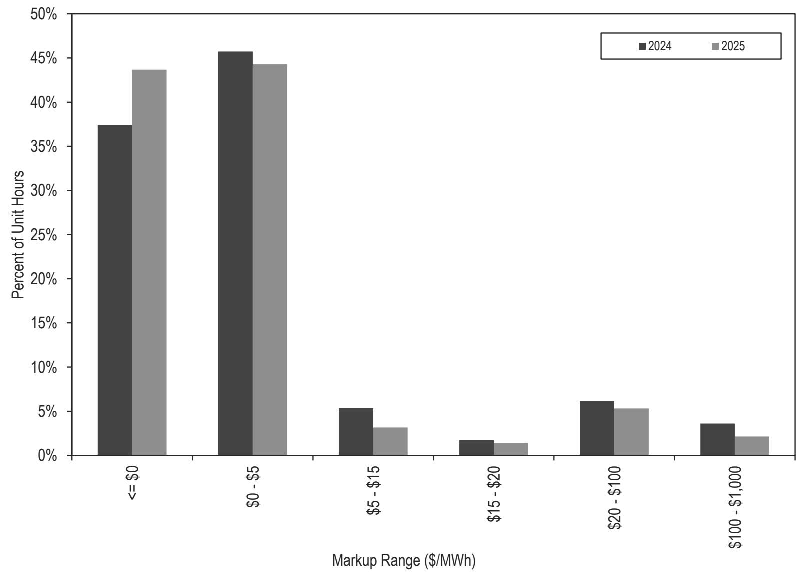


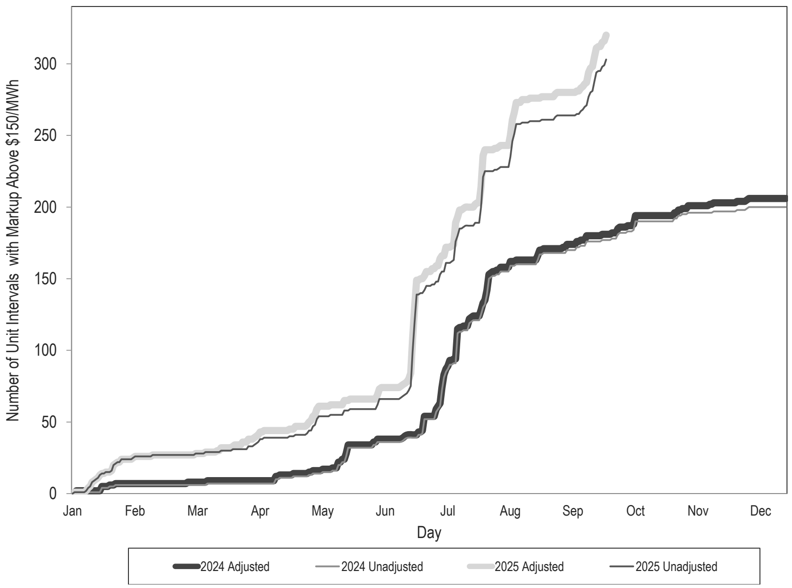
Figure 3-69 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2024 and the first nine months of 2025 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2025, 43.7 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 2.1 percent of oil fired unit hours had a maximum markup above $100 per MWh.

The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Figure 3-70 shows the number of marginal unit intervals in the first nine months of 2025 and 2024 with markup above $150 per MWh.

Figure 3-70 Cumulative number of unit intervals with markups above $150 per MWh: January 2024 through September 2025



Day-Ahead Markup Index

Table 3-119 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers.[190]

In the six months between April and September of 2025, the average dollar markup of units with offer prices less than $10 was positive ($6.63 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was positive ($6.38 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the six months between April and September of 2025, 1.3 percent had offer prices above $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the six months between April and September of 2025 was more than $550 per MWh.

Table 3-119 Average day-ahead marginal unit markup index (By offer price category, unadjusted): April through September, 2025

	2025 (Apr - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $10	2.15	$6.63	7.1%
$10 to $15	0.66	$6.38	9.1%
$15 to $20	0.11	$0.97	13.6%
$20 to $25	0.05	$0.41	15.0%
$25 to $50	0.09	$2.27	43.9%
$50 to $75	0.24	$14.74	7.2%
$75 to $100	0.23	$19.61	2.0%
$100 to $125	0.29	$31.22	0.6%
$125 to $150	0.32	$45.19	0.1%
>= $150	0.27	$76.94	1.3%
All Offers	0.23	$4.96	100.0%

190 MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors and markup index require accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate markup index for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

Table 3-120 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers.

Table 3-120 Average day-ahead marginal unit markup index (By offer price category, adjusted): April through September, 2025

	2025 (Apr - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $10	2.18	$6.85	7.1%
$10 to $15	0.73	$7.32	9.1%
$15 to $20	0.18	$2.51	13.6%
$20 to $25	0.11	$2.21	15.0%
$25 to $50	0.16	$4.82	43.9%
$50 to $75	0.29	$17.71	7.2%
$75 to $100	0.27	$22.89	2.0%
$100 to $125	0.32	$35.06	0.6%
$125 to $150	0.34	$47.62	0.1%
>= $150	0.30	$87.37	1.3%
All Offers	0.29	$7.10	100.0%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly based on changes in costs. Table 3-121 shows the caps on the three parts of cost-based and price-based offers.

Table 3-121 Cost-based and price-based offer caps

Offer Type	No Load and Start Cost Option	Incremental Offer Curve Cap	No Load Cost Cap	Start Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies		
Price-Based	Cost-Based	$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies
	Price-Based		No cap but can only be changed twice a year.	No cap but can only be changed twice a year.

Table 3-122 shows the number of units that chose the cost-based option and the price-based option. In the first nine months of 2025, 90 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, the same as in the first nine months of 2024.

Table 3-122 Number of units selecting cost-based and price-based no load and start costs: January through September, 2024 and 2025

No Load and Start Cost Option	2024 (Jan-Sep) Number of units	Percent	2025 (Jan-Sep) Number of units	Percent
Cost-Based	480	90%	468	90%
Price-Based	51	10%	50	10%
Total	531	100%	518	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-123 shows the average markup in the no load and start costs in the first nine months of 2024 and 2025. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs. The price-based offers were lower than the cost-based offers. In the first nine months of 2025, generators that selected the price-based start and no load option offered on average with a positive markup on the no load cost and with very large positive markups on the start costs.

Table 3-123 No load and start cost markup: January through September, 2024 and 2025

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2024 (Jan-Sep)	Cost-Based	(8%)	(6%)	(6%)	(7%)
	Price-Based	10%	197%	183%	186%
2025 (Jan-Sep)	Cost-Based	(14%)	(5%)	(5%)	(7%)
	Price-Based	23%	139%	123%	122%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first nine months of 2025, 9.8 percent of the marginal units set prices based on cost-based offers, 2.3 percentage points higher than in the first nine months of 2024.

The efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer in the PJM market rules is not correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. The market rules allow these overstated cost-based offers. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are "directly related to energy production." The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and allows for multiple interpretations, which could lead to tariff violations. The incorrect rules lead to higher energy market prices and higher uplift.

There are three types of costs identified in PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer, a variable cost, is that the cost is "directly related to electric production."[191]

Variable costs, as defined in the PJM rules, are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.[192]

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

191 See 167 FERC ¶ 61,030 (2019).
192 See OA Schedule 2 § 1.1(a).

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

The MMU recommends that PJM require that the level of costs includable in cost-based offers in the energy market not exceed the unit's short run marginal cost.

Fuel Cost Policies

Fuel cost policies (FCP) document the process by which market sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel Cost Policy Review

Table 3-124 shows the status of all fuel cost policies (FCP). As of September 30, 2025, 715 units (92 percent) had an FCP passed by the MMU and 65 units (eight percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 15,740 MW. All units' FCPs were approved by PJM. As of September 30, 2025, 612 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.[193]

Table 3-124 FCP Status for PJM generating units: September 30, 2025

	MMU Status				Units without
PJM Status	Pass	Submitted	Fail	Total	FCPs
Approved	715	0	65	780	
Rejected	0	0	0	0	
Under Review	0	0	0	0	
Customer Input Required	0	0	0	0	
Submitted	0	0	0	0	
Total	715	0	65	780	612

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM approved every FCP failed by the MMU.

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run

193 See OA Schedule 2 § 2.1.

marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic.[194] Verifiable means that the FCP requires a market seller to provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[195] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's standard effectively requires algorithmic fuel cost policies by describing the requirements.[196] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[197]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some fuel cost policies did not meet are: accuracy (reflect applicable costs accurately); and fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).[198]

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in dollars per MWh or in dollars per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar units.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were the use of available market information that results in inaccurate and overstated expected costs. Overstated costs permit the exercise of market power.

Some of the failed fuel cost polices include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is not a market clearing price and is not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Units are required to have an approved fuel cost policy before they can submit nonzero cost-based offers or request from PJM the use of a temporary cost method. The temporary cost offer method allows units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy, allowing the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

194 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) at P 11 ("October 7th Filing").
195 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
196 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
197 September 16th Filing at P 8.
198 See PJM Operating Agreement Schedule 2 § 2.3 (a).

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

Cost-Based Offer Penalties

Market sellers are assessed penalties when they submit cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[199] Penalties are assessed when both PJM and the MMU are in agreement.

In the first nine months of 2025, 28 penalty cases were identified, 27 have been assessed cost-based offer penalties and one remains pending. These cases were for 28 units owned by 11 different companies. Table 3-125 shows the penalties by the year in which participants were notified.

Table 3-125 Cost-based offer penalty cases by year notified: May 2017 through September 2025

Year notified	Cases	Assessed penalties	Self Identified	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	0	1	0	55	16
2018	187	161	0	26	0	138	35
2019	57	57	0	0	0	57	19
2020	142	137	24	5	0	124	25
2021	129	124	42	5	0	124	21
2022	116	116	51	0	0	110	20
2023	65	65	13	0	0	61	18
2024	77	77	39	0	0	67	21
2025	28	27	2	0	1	28	11
Total	858	820	171	37	1	516	81

Since 2017, of the 858 penalty cases, 820 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM and one remains pending. A total of 171 were self identified by market sellers. The 820 cases were from 516 units owned by 81 different companies. The total penalties were $6.0 million, charged to units that totaled 165,275 available MW. The average penalty was $1.60 per available MW. This means that a 100 MW unit would have paid a penalty of $3,840.[200] There is no link between the increased costs to the market that result from a penalized fuel cost policy and the amount of the penalty. The increased costs to the market can exceed the penalty payment and the reverse can also be true. Table 3-126 shows the total cost-based offer penalties since 2017 by year.

Table 3-126 Cost-based offer penalties by year: May 2017 through September 2025

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	21	$556,826	16,930	$1.56
2018	127	35	$1,242,102	25,743	$2.28
2019	73	24	$378,245	15,073	$1.14
2020	140	28	$407,283	21,908	$0.85
2021	125	27	$753,463	24,808	$1.31
2022	123	22	$1,613,621	24,385	$2.76
2023	61	16	$333,948	10,383	$1.33
2024	79	22	$549,736	21,900	$1.05
2025	27	10	$181,937	4,145	$1.84
Total	847	78	$6,017,161	165,275	$1.60

The incorrect cost-based offers resulted from incorrect application of fuel cost policies, lack of approved fuel cost policies, fuel cost policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

Penalties do not apply when PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so. This practice is inappropriate and should stop.

The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy.

199 See OA Schedule 2 § 6.

200 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced or updated with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers for thermal resources. In 2022, PJM made updates recommended by the MMU to Manual 15 to add straightforward descriptions for some of the most essential cost offer calculations.[201]

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[202] The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing, subject to revisions requested by FERC.[203] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[204] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

201 See PJM Manual 15: Cost Development Guidelines, Revision 47 (Oct. 1, 2025).
202 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
203 167 FERC ¶ 61,030 (2019).
204 168 FERC ¶ 61,134 (2019).

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2024.

Table 3-127 shows the average VOM by unit type. The VOM equals the sum of variable operating cost, major maintenance adder and minor maintenance adder as submitted by market participants.

Table 3-127 Effective VOM costs in dollars per MWh in 2024

Unit Type	VOM ($/MWh)
Combined Cycles	$3.00
Combustion Turbines and RICE	$22.62
Gas/Oil Steam Turbines	$12.19
Coal	$6.01

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data. For example, a market seller can provide data from ten years ago without any supporting documentation as long as the data from the current year has documentation. PJM's review is dependent on the level of detail provided by the market seller. As a result of questions raised by the MMU, PJM now requires more details from market sellers, which has led to the appropriate exclusion of expenses that were previously included.[205]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

On February 17, 2023, PJM filed tariff revisions changing the rules related to VOM costs. The changes included separating maintenance expenses into major and minor maintenance, allowing the use of default adders for minor maintenance and operating costs and eliminating the annual review requirement for units that choose to use default adders. The proposal, that included the tariff changes, also included Manual 15 changes that introduced additional documentation requirements. Regarding maintenance expenses, market participants will be required to provide all supporting documentation for all expenses submitted, regardless of year. Regarding operating expenses, market participants will be required to provide the amount of consumables used during operation and the cost per unit of each consumable. On April 18, 2023, FERC accepted PJM's filing. Table 3-128 shows the default adders for operating cost and minor maintenance.

Table 3-128 Default operating cost and minor maintenance adder: 2024

Unit Type	Operating Cost ($/MWh)	Minor Maintenance Cost ($/MWh)
Combined Cycle	0.46	1.13
Combustion Turbine	0.86	4.14
Reciprocating Engine	1.87	4.64
Steam Turbine	3.31	1.97

205 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>

The MMU recommended that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. The revisions to Manual 15 based on the February 17, 2023, filing included this requirement.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. The revisions to Manual 15 based on the February 17, 2023, filing partially included this requirement. Even though Manual 15 requires maintenance expenses to be the result of operating hours, starts or a combination of the two, the expenses are not tied to a maintenance cycle. Therefore, it is not possible to distinguish between maintenance that resulted from operating the resource versus maintenance from normal wear and tear.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[206]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15. On December 2, 2022, PJM filed tariff changes removing labor costs from cost-based offers. The changes were approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[207]

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the unit is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU recommended changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

In 2022, the MMU and PJM proposed changing the start cost definition of units with a steam process to include the costs from the beginning of the start sequence to dispatchable.[208] The new definition included what is commonly consider soak costs in the start cost. The new definition was combined with the elimination of make whole payments to units with a steam process for MW produced before the unit becomes dispatchable. The proposal was approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[209]

Even though the MMU developed and supported the new definition, it is important to recognize that this approach should be temporary until PJM implements an approach that reflects soak time, soak costs and soak energy output. The main shortcoming of the new definition is that PJM models do not properly value the energy produced during the soak process (soak energy output). Instead, the proposal simply assumes that such MWh are valued at PJM's station service rate. The ideal solution is to model start costs and soak

206 The peak adder is equal to $300 times three divided by 5 MW.
207 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.
208 *See* "Start Cost Alternate Proposal," MMU presentation to the Cost Development Subcommittee. (December 2, 2021) <20211202-item-06-start-cost-alternate-proposal.ashx>.
209 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

costs separately since there are revenues associated with the MWh produced during soaking, while during the start process there are no MWh being injected into the grid.

The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Gas Pipeline Penalties

Section 2.2.2 of PJM Manual 15 states that gas pipeline penalties are not includable in cost-based offers. Penalties can be incurred by units for many reasons, for example, withdrawing gas not nominated and deviating from an imposed threshold during an operational flow order. Any unit with cost-based offers that include gas pipeline penalties will be subject to penalties per Schedule 2 of the PJM Operating Agreement.

Many Market Sellers rely on independent third party quotes to estimate or determine the gas spot price. The quotes received from these third parties should not be based on incurring gas pipeline penalties. It is recommended that Market Sellers confirm with their third parties that gas is available to them without the need to incur gas pipeline penalties. If that is not possible, the units should be unavailable until the third party can confirm that gas is available without incurring penalties.

Frequently Mitigated Units (FMU) and Associated Units (AU)

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[210] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder in January. In 2022, 2023, and 2024, no units qualified for an FMU adder. In the first nine months of 2025, no units qualified for an FMU adder.

Table 3-129 shows, by month, the number of FMUs and AUs from January 2021 through September 2025. For example, in January 2021, there were zero units that qualified as an FMU or AU in Tier 1, one unit qualified as an FMU or AU in Tier 2, and zero units qualified as an FMU or AU in Tier 3.

210 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 Annual State of the Market Report for PJM*, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

Table 3-129 Number of frequently mitigated units and associated units (By month): January 2021 through September 2025

	2021				2022				2023				2024				2025			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

Market Performance

Ownership of Marginal Resources

Table 3-130 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[211] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first nine months of 2025, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2025, the offers of one company resulted in 16.3 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 40.8 percent of the real-time load-weighted average PJM system LMP. In the first nine months of 2025, the offers of one company resulted in 15.0 percent of the peak hour real-time load-weighted PJM system LMP.

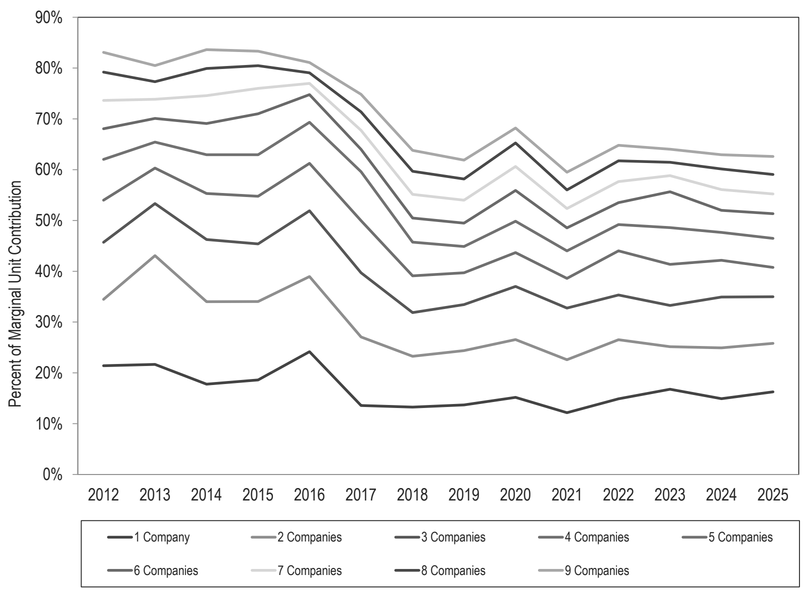
211 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-130 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2024 and 2025

2024 (Jan - Sep)						2025 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	14.9%	14.9%	1	15.8%	15.8%	1	16.3%	16.3%	1	15.0%	15.0%
2	10.0%	24.9%	2	12.7%	28.5%	2	9.5%	25.8%	2	10.1%	25.1%
3	10.0%	34.9%	3	8.3%	36.8%	3	9.2%	35.0%	3	7.3%	32.5%
4	7.3%	42.2%	4	7.1%	43.9%	4	5.8%	40.8%	4	5.2%	37.6%
5	5.5%	47.6%	5	4.7%	48.6%	5	5.7%	46.5%	5	5.1%	42.8%
6	4.3%	52.0%	6	4.5%	53.1%	6	4.8%	51.3%	6	4.9%	47.7%
7	4.1%	56.1%	7	3.9%	57.1%	7	3.9%	55.2%	7	4.8%	52.5%
8	4.1%	60.1%	8	3.8%	60.8%	8	3.8%	59.0%	8	4.6%	57.1%
9	2.8%	62.9%	9	3.0%	63.9%	9	3.6%	62.6%	9	4.3%	61.4%
Other (93 companies)	37.1%	100.0%	Other (89 companies)	36.1%	100.0%	Other (104 companies)	37.4%	100.0%	Other (100 companies)	38.6%	100.0%

Figure 3-71 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies for the first nine months of every year since 2012.

Figure 3-71 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2012 through 2025



Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[212] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. A full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-131 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $2.28 per MWh in the first nine months of 2024 to $2.95 per MWh in the first nine months of 2025. The adjusted markup contribution of coal units in the first nine months of 2025 was $0.64 per MWh, an increase of $0.40 per MWh from the first nine months of 2024. The adjusted markup component of gas fired units in the first nine months of 2025 was $2.93 per MWh, an increase of $0.43 per MWh from the first nine months of 2024. The markup component of wind units was

212 The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

$0.01 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first nine months of 2025, among the wind units that were marginal, 68.7 percent had negative offer prices.

Table 3-131 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: January through September, 2024 and 2025[213]

		2024 (Jan - Sep)		2025 (Jan - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.24)	$0.24	$0.23	$0.64
Gas	CC	$1.01	$1.83	$0.54	$2.00
Gas	CT	$0.13	$0.61	$0.12	$0.91
Gas	RICE	($0.01)	$0.01	$0.03	$0.05
Gas	Steam	($0.02)	$0.05	($0.15)	($0.04)
Municipal Waste	RICE	$0.01	$0.01	$0.02	$0.02
Oil	CC	($0.00)	($0.00)	($0.00)	$0.01
Oil	CT	($0.52)	($0.44)	($0.91)	($0.72)
Oil	RICE	($0.00)	$0.00	$0.00	$0.01
Oil	Steam	($0.18)	($0.16)	($0.07)	($0.04)
Other	Battery	$0.00	$0.00	$0.01	$0.01
Other	Solar	$0.10	$0.10	$0.01	$0.01
Other		$0.01	$0.01	$0.07	$0.07
Wind		$0.02	$0.02	$0.01	$0.01
Total		$0.30	$2.28	($0.09)	$2.95

Markup Component of Real-Time Price

Table 3-132 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-133 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first nine months of 2025, when using unadjusted cost-based offers, -$0.09 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $2.94 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2025, the peak markup component was highest in July, $2.74 per MWh using unadjusted cost-based offers and $6.66 per MWh using adjusted cost-based offers. This corresponds to 3.5 percent and 8.6 percent of the real-time peak load weighted average LMP in July.

213 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-132 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2024 through September 2025

	2024			2025		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($3.81)	($2.55)	($5.05)	($2.00)	($1.17)	($2.83)
Feb	$0.12	$0.60	($0.36)	($0.22)	($0.59)	$0.15
Mar	($0.14)	($0.68)	$0.34	($0.37)	($1.02)	$0.22
Apr	$1.49	$2.00	$0.92	$0.68	$0.32	$1.07
May	($0.57)	($0.17)	($1.00)	($0.54)	($0.29)	($0.79)
Jun	($0.45)	($1.01)	$0.11	$0.29	($0.08)	$0.69
Jul	$3.72	$6.10	$1.11	$0.55	$2.74	($1.87)
Aug	$2.31	$4.47	($0.07)	($0.87)	($0.94)	($0.79)
Sep	($0.33)	($0.28)	($0.37)	$1.52	$1.48	$1.56
Oct	($1.60)	($1.64)	($1.56)			
Nov	($0.06)	$0.76	($0.81)			
Dec	($1.38)	($1.43)	($1.32)			
Total	($0.01)	$0.67	($0.70)	($0.09)	$0.12	($0.41)

Table 3-133 Monthly markup components of real-time load-weighted LMP (Adjusted): January 2024 through September 2025

	2024			2025		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.78)	$0.62	($2.16)	$2.16	$3.38	$0.95
Feb	$1.77	$2.26	$1.28	$3.21	$3.08	$3.35
Mar	$1.29	$0.88	$1.66	$2.40	$1.79	$2.94
Apr	$3.03	$3.65	$2.35	$3.53	$3.24	$3.85
May	$1.38	$2.00	$0.72	$1.68	$2.16	$1.20
Jun	$1.50	$1.28	$1.72	$3.34	$3.47	$3.21
Jul	$6.03	$8.87	$2.91	$4.01	$6.66	$1.08
Aug	$4.15	$6.54	$1.51	$1.72	$2.08	$1.37
Sep	$1.48	$1.72	$1.25	$3.86	$4.05	$3.66
Oct	$0.24	$0.38	$0.08			
Nov	$1.79	$2.79	$0.88			
Dec	$0.98	$1.06	$0.90			
Total	$1.98	$2.86	$1.08	$2.94	$3.46	$2.31

Hourly Markup Component of Real-Time Prices

Figure 3-72 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first nine months of 2025 and 2024. Figure 3-73 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in the first nine months of 2025 and 2024.

Figure 3-72 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January 2024 through September 2025

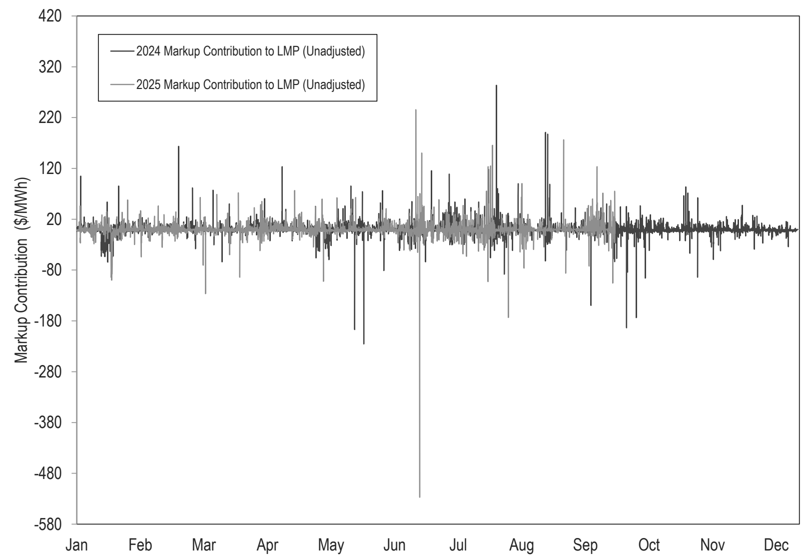
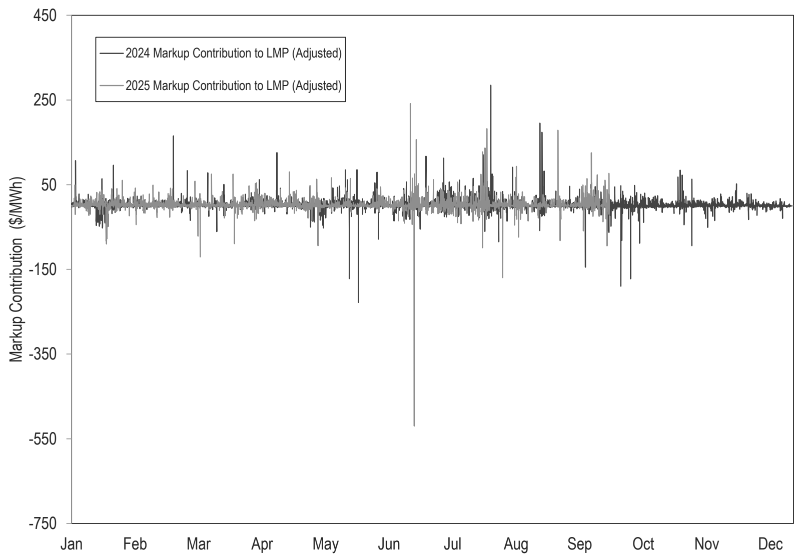


Figure 3-73 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January 2024 through September 2025



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first nine months of 2024 and 2025 in Table 3-134 and for adjusted offers in Table 3-135.[214] The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2025, was in the DPL Zone, -$2.09 per MWh, while the highest was in the BGE Zone, $0.72 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2025, was in the DPL Zone, -$2.88 per MWh, while the highest was in the PE Zone, $1.23 per MWh.

Table 3-134 Real-time average zonal markup component (Unadjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	($0.18)	$0.73	($1.11)	($1.61)	($2.12)	($1.09)
AEP	$0.49	$1.39	($0.43)	$0.17	$0.72	($0.38)
APS	$0.16	$0.93	($0.63)	$0.14	$0.53	($0.25)
ATSI	$0.29	$1.08	($0.53)	$0.05	$0.56	($0.45)
BGE	$1.80	$2.55	$1.02	$0.72	$0.78	$0.66
COMED	$0.26	$1.06	($0.56)	$0.23	$0.80	($0.35)
DAY	$0.14	$0.95	($0.70)	$0.01	$0.45	($0.43)
DOM	$0.69	$1.44	($0.08)	($0.06)	$0.09	($0.22)
DPL	($0.11)	$0.70	($0.94)	($2.09)	($2.88)	($1.29)
DUKE	($0.23)	$0.68	($1.17)	($0.01)	$0.41	($0.43)
DUQ	($0.02)	$0.58	($0.63)	$0.01	$0.55	($0.54)
EKPC	($0.16)	$0.59	($0.94)	($0.09)	$0.16	($0.34)
JCPLC	($0.32)	$0.61	($1.28)	($0.75)	($0.53)	($0.98)
MEC	($0.52)	$0.44	($1.51)	($0.73)	($0.36)	($1.11)
OVEC	($0.29)	$0.26	($0.84)	$0.15	$0.76	($0.46)
PE	($0.12)	$0.57	($0.82)	$0.62	$1.23	$0.00
PECO	($0.21)	$0.57	($1.02)	($1.69)	($2.25)	($1.12)
PEPCO	$1.11	$1.68	$0.53	$0.41	$0.19	$0.62
PPL	($0.62)	$0.18	($1.45)	($1.14)	($0.78)	($1.50)
PSEG	($0.23)	$0.80	($1.28)	($0.63)	($0.43)	($0.83)
REC	($0.11)	$0.70	($0.95)	$0.17	$0.27	$0.08

214 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-135 Real-time average zonal markup component (Adjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.54	$2.58	$0.47	$1.28	$1.07	$1.49
AEP	$2.47	$3.57	$1.33	$3.29	$4.15	$2.42
APS	$2.22	$3.23	$1.18	$3.34	$4.07	$2.59
ATSI	$2.29	$3.35	$1.21	$3.15	$3.99	$2.32
BGE	$4.17	$5.23	$3.09	$4.24	$4.69	$3.79
COMED	$2.05	$3.08	$1.00	$2.99	$3.93	$2.05
DAY	$2.16	$3.19	$1.09	$3.14	$3.89	$2.37
DOM	$2.91	$3.91	$1.88	$3.42	$3.99	$2.85
DPL	$1.74	$2.69	$0.76	$0.98	$0.61	$1.35
DUKE	$1.72	$2.84	$0.56	$3.03	$3.75	$2.30
DUQ	$2.00	$2.87	$1.11	$3.07	$3.96	$2.19
EKPC	$1.80	$2.76	$0.80	$2.99	$3.54	$2.44
JCPLC	$1.42	$2.47	$0.33	$2.15	$2.67	$1.62
MEC	$1.33	$2.51	$0.13	$2.23	$2.96	$1.49
OVEC	$1.62	$2.36	$0.85	$3.10	$4.00	$2.20
PE	$1.87	$2.79	$0.92	$3.77	$4.71	$2.83
PECO	$1.47	$2.39	$0.53	$1.13	$0.85	$1.40
PEPCO	$3.40	$4.25	$2.54	$3.85	$4.01	$3.70
PPL	$1.13	$2.12	$0.12	$1.70	$2.39	$1.01
PSEG	$1.52	$2.66	$0.34	$2.30	$2.80	$1.80
REC	$1.69	$2.61	$0.74	$3.24	$3.64	$2.84

Markup by Real-Time Price Levels

Table 3-136 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-136 Real-time markup contribution (By load-weighted LMP category, unadjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($1.96)	1.7%	($3.99)	0.1%
$10 to $15	($1.88)	13.7%	($2.23)	1.1%
$15 to $20	($2.31)	17.9%	($1.78)	7.8%
$20 to $25	($1.90)	17.4%	($1.91)	12.0%
$25 to $50	$0.09	37.7%	($1.65)	53.3%
$50 to $75	$5.04	6.9%	$0.71	15.5%
$75 to $100	$6.47	2.1%	$3.58	4.8%
$100 to $125	$5.95	1.2%	$10.08	2.2%
$125 to $150	$17.72	0.5%	$9.10	1.1%
>= $150	$34.25	0.8%	$11.76	2.0%

Table 3-137 Real-time markup contribution (By load-weighted LMP category, adjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($1.19)	1.7%	($2.84)	0.1%
$10 to $15	($0.83)	13.7%	($1.07)	1.1%
$15 to $20	($0.96)	17.9%	($0.29)	7.8%
$20 to $25	($0.28)	17.4%	($0.07)	12.0%
$25 to $50	$2.34	37.7%	$1.07	53.3%
$50 to $75	$8.01	6.9%	$4.43	15.5%
$75 to $100	$9.67	2.1%	$7.90	4.8%
$100 to $125	$9.84	1.2%	$14.63	2.2%
$125 to $150	$21.85	0.5%	$15.13	1.1%
>= $150	$37.36	0.8%	$19.23	2.0%

Markup by Company

Table 3-138 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2025, when using unadjusted cost-based offers, the markup of one company accounted for 0.8 percent of the load-weighted average LMP, the markup of the top five companies accounted for 2.8 percent of the load-weighted average LMP and the markup of all companies accounted for -0.3 percent of the load-weighted average LMP. The share of top five companies' markup contribution to the load-weighted average LMP decreased and the dollar values of their markup decreased in the first nine months of 2025. The markup contribution to the load-weighted average LMP decreased and share of the markup contribution to the load-weighted average LMP decreased in the first nine months of 2025. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-138 Markup component of real-time load-weighted average LMP by Company: January through September, 2024 and 2025

	2024 (Jan - Sep)				2025 (Jan - Sep)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.66	1.9%	$0.76	2.2%	$0.43	0.8%	$0.63	1.2%
Top 2 Companies	$0.99	2.9%	$1.25	3.6%	$0.82	1.6%	$1.19	2.4%
Top 3 Companies	$1.28	3.7%	$1.62	4.7%	$1.15	2.3%	$1.71	3.4%
Top 4 Companies	$1.50	4.4%	$1.97	5.7%	$1.39	2.8%	$2.21	4.4%
Top 5 Companies	$1.67	4.9%	$2.21	6.4%	$1.54	3.0%	$2.49	4.9%
All Companies	$0.29	0.9%	$2.28	6.7%	($0.15)	(0.3%)	$2.89	5.7%

Day-Ahead Markup[215]

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead load-weighted average LMP by primary fuel and unit type is shown in Table 3-139. INC, DEC and up to congestion transactions (UTC) have zero markups. The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer and the cost-based offer excluding the 10 percent adder.

Table 3-139 shows the markup component of LMP for marginal generating resources. The adjusted markup component of LMP for coal fired units was $0.28 per MWh in the six months between April and September of 2025. The adjusted markup component of LMP for gas fired CC units was $1.38 per MWh in the six months between April and September of 2025.

215 MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors and markup index require accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate markup index for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

Table 3-139 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: April through September, 2025

		2025 (Apr - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.12)	$0.28
Gas	CC	$0.53	$0.96
Gas	CT	$0.32	$0.48
Gas	RICE	($0.00)	$0.00
Gas	Steam	($0.16)	($0.07)
Oil	CC	$0.00	$0.00
Oil	CT	($0.01)	($0.01)
Oil	RICE	$0.00	$0.00
Oil	Steam	($0.05)	($0.04)
Other	Solar	$1.42	$1.42
Other	Steam	$0.01	$0.01
Wind	Wind	$0.71	$0.71
Total		$2.64	$3.76

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-140 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. Table 3-141 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the six months between April and September of 2025, when using unadjusted cost-based offers, $2.64 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $3.76 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the six months between April and September of 2025, the peak markup component was highest in July, $7.59 per MWh using unadjusted cost-based offers and $9.07 per MWh using adjusted cost-based offers. This corresponds to 8.6 percent and 10.2 percent of the day-ahead peak load weighted average LMP in July.

Table 3-140 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: April 2025 through September 2025

	2025		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Apr	$2.45	$3.01	$1.82
May	($0.44)	($1.07)	$0.19
Jun	$2.64	$4.06	$1.07
Jul	$4.10	$7.59	$0.19
Aug	$4.16	$5.53	$2.77
Sep	$1.71	$3.93	($0.66)
Total	$2.64	$4.16	$0.91

Table 3-141 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: April 2025 through September 2025

	2025		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Apr	$3.30	$4.04	$2.48
May	$0.81	$0.10	$1.52
Jun	$3.75	$5.04	$2.33
Jul	$5.61	$9.07	$1.74
Aug	$5.29	$6.53	$4.02
Sep	$2.20	$4.03	$0.25
Total	$3.76	$5.14	$2.09

Markup Component of Day-Ahead Zonal Prices

Table 3-142 shows the markup component of annual average day-ahead price using unadjusted cost-based offers for each zone and for adjusted offers in Table 3-143.

The smallest zonal all hours average markup component using unadjusted cost-based offers for the six months between April and September of 2025 was in OVEC, $2.16 per MWh, while the highest was in PEPCO, $6.75 per MWh. The smallest zonal on peak average markup using unadjusted cost-based offers was in OVEC, $3.22 per MWh, while the highest was in PEPCO, $12.26 per MWh.

Table 3-142 Day-ahead average zonal markup component (Unadjusted): April through September, 2025

	2025 (Apr - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$5.01	$9.36	$0.77
AEP	$4.16	$6.74	$1.63
APS	$3.76	$5.97	$1.59
ATSI	$5.16	$8.60	$1.78
BGE	$4.47	$7.60	$1.42
COMED	$4.13	$4.58	$3.68
DAY	$3.60	$5.51	$1.73
DOM	$2.88	$4.06	$1.72
DPL	$3.35	$6.35	$0.44
DUKE	$3.47	$5.47	$1.52
DUQ	$4.03	$6.88	$1.26
EKPC	$3.99	$6.59	$1.45
JCPLC	$4.94	$9.39	$0.59
MEC	$2.51	$5.09	($0.01)
OVEC	$2.16	$3.22	$0.97
PE	$3.39	$5.61	$1.22
PECO	$5.56	$10.60	$0.66
PEPCO	$6.75	$12.26	$1.37
PPL	$4.22	$8.28	$0.25
PSEG	$4.01	$7.39	$0.70
REC	$4.25	$7.76	$0.85

Table 3-143 Day-ahead average zonal markup component (Adjusted): April through September, 2025

	2025 (Apr - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$6.22	$10.41	$2.12
AEP	$5.56	$7.84	$3.32
APS	$4.82	$6.65	$3.01
ATSI	$6.24	$9.50	$3.03
BGE	$5.55	$7.80	$3.34
COMED	$5.25	$5.82	$4.68
DAY	$4.87	$6.54	$3.23
DOM	$4.00	$4.93	$3.09
DPL	$4.79	$7.65	$1.98
DUKE	$4.62	$6.38	$2.89
DUQ	$5.07	$7.66	$2.53
EKPC	$5.31	$7.70	$2.94
JCPLC	$6.39	$10.77	$2.08
MEC	$3.95	$6.19	$1.74
OVEC	$3.74	$4.80	$2.57
PE	$4.75	$6.99	$2.53
PECO	$6.93	$11.90	$2.04
PEPCO	$7.48	$11.83	$3.21
PPL	$5.64	$9.56	$1.77
PSEG	$5.36	$8.63	$2.13
REC	$5.51	$8.77	$2.33

Markup by Day-Ahead Price Levels

Table 3-144 and Table 3-145 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-144 Day-ahead average markup component (By LMP category, unadjusted): April through September, 2025

	2025 (Apr - Sep)	
LMP Category	Markup Component	Frequency
$10 to $15	($1.42)	0.9%
$15 to $20	($0.28)	8.1%
$20 to $25	($0.45)	13.4%
$25 to $50	$1.06	52.5%
$50 to $75	$5.39	16.4%
$75 to $100	$6.98	5.2%
$100 to $125	$12.22	1.6%
$125 to $150	$11.64	0.5%
>= $150	$13.48	1.3%

Table 3-145 Day-ahead average markup component (By LMP category, adjusted): April through September, 2025

	2025 (Apr - Sep)	
LMP Category	Markup Component	Frequency
$10 to $15	($0.45)	0.9%
$15 to $20	$0.68	8.1%
$20 to $25	$0.65	13.4%
$25 to $50	$2.37	52.5%
$50 to $75	$5.95	16.4%
$75 to $100	$7.87	5.2%
$100 to $125	$13.03	1.6%
$125 to $150	$12.55	0.5%
>= $150	$14.77	1.3%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment evaluates the extent to which participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[216]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, P is the market price, and MC is the average marginal cost of production. This is called the Lerner Index. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. As HHI decreases, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices can reach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose higher prices on customers. The Lerner Index is a measure of market power that connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level implies substantial markups due to the low short run price elasticity of

216 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[217] Using the Lerner Index, the elasticity of -0.2 implies, for example, an average markup ranging from 25 to 50 percent at the low end of the moderately concentrated threshold HHI of 1000:[218]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 0.5$$

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $50.61 per MWh and an average HHI of 686 in the first nine months of 2025, average PJM prices would theoretically range from $61 to $77 per MWh, an implied markup of 17.2 to 34.3 percent, using the elasticity range of -0.2 to -0.4. Given the elasticity estimates, the theoretical prices exceed marginal costs because the exercise of market power is profit maximizing. In the PJM market, market power mitigation limits the exercise of market power, so prices cannot reach the higher theoretical level. Actual prices, averaging $50.51 per MWh with markups at -0.2 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-146 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first nine months of 2025, 3.0 percent of real-time marginal unit intervals and 3.3 percent of day-ahead marginal unit hours included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit.

Table 3-146 Percent of real-time marginal unit intervals with markup and local market power: January through September, 2025

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	40.1%	3.1%	43.3%	52.7%	6.2%	58.9%
Zero Markup	21.6%	5.8%	27.4%	17.7%	7.3%	25.0%
$0 to $5	11.6%	1.1%	12.6%	7.4%	1.4%	8.9%
$5 to $10	4.3%	0.7%	5.0%	2.6%	0.4%	3.0%
$10 to $15	2.1%	0.6%	2.7%	1.2%	0.3%	1.5%
$15 to $20	1.1%	0.3%	1.3%	0.4%	0.3%	0.7%
$20 to $25	0.7%	0.1%	0.8%	0.2%	0.1%	0.3%
$25 to $50	3.3%	0.3%	3.6%	0.7%	0.4%	1.0%
$50 to $75	1.4%	0.1%	1.5%	0.2%	0.1%	0.3%
$75 to $100	1.1%	0.1%	1.2%	0.1%	0.0%	0.2%
Above $100	0.5%	0.0%	0.6%	0.1%	0.1%	0.2%
Total Positive Markup	26.1%	3.3%	29.3%	13.0%	3.0%	16.1%
Total	87.9%	12.1%	100.0%	83.5%	16.5%	100.0%

The markup of marginal units was zero or negative in 83.9 percent of real-time marginal unit intervals and 70.7 percent of day-ahead marginal unit intervals in the first nine months of 2025. Zero and negative markup are the expected results in a competitive market. Pivotal suppliers in the aggregate market also set prices with high markups in the first nine months of 2025. The 26.1 percent of day-ahead marginal units and 13.0 percent of real-time marginal units setting price with a markup without failing the TPS test could represent units with aggregate market power or units that maintain markup in their offer for times when they have local market power. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.

217 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices," <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

218 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

Energy Uplift (Operating Reserves)

In a well designed wholesale power market, energy uplift is paid as credits to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating at the direction of PJM, to operate at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, dispatch differential lost opportunity credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Fast start pricing, implemented on September 1, 2021, required a new uplift credit to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. The result of fast start pricing is to create a greater reliance on uplift rather than price signals as an incentive to follow PJM's instructions.

Uplift is an inherent part of the PJM market design. Part of uplift is the result of the nonconvexity of power production costs. Uplift payments cannot be eliminated, but uplift payments should be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[2] [3] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design concept incorporates efficient prices with minimal uplift payments.

But PJM's practice does not minimize uplift payments. In some cases, PJM pays uplift that is not consistent with the rules. In some cases, the rules permit the payment of uplift that is not consistent with the goal of PJM market design. Regulation revenues should be included as an offset to the daily uplift calculation for generators that receive regulation revenues, but are not currently included. The need for uplift should be calculated on a daily basis, as incorporated in the initial PJM market design, rather than on an hourly segment basis. The goal of uplift should be to ensure that units are not required to run at a loss on a daily basis. The goal should not be to lock in profits in some hourly segments and require uplift in other hourly segments. In the case where PJM makes multiday commitments, the uplift calculation should cover the entire multiday period rather than allowing a generator to be paid uplift on day one and earn significant profits on day three. There are identified improvements to PJM's application of the rules, and to the market design and uplift rules that could reduce uplift payments to the efficient level.

PJM's day-ahead generator credits and balancing generator credits are calculated by operating day and by hourly segments. Segments for day-ahead generator credits equal the hours in which the unit cleared in the day-ahead market. Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time or in excess of the hours cleared in the day-ahead market become new segments. The net revenues in those new segments are not counted as contributing to covering costs in the initial segment. The reverse is also true. Uplift is paid even when total net revenues cover or more than cover costs when the entire day is included.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the

1 Losses occur when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers, and the unit is following PJM instructions including both commitment and dispatch instructions. There is no corresponding assurance required when units are self scheduled or not following PJM dispatch instructions.

2 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

3 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the real-time energy market. The current payment structure for DR is an inefficient element of the PJM market design.[4]

Polar Vortex 2025 resulted in a significant increase in uplift payments as a result of the fact that PJM chose to prepare for the weather related risks of Polar Vortex 2025 in very different ways than for Winter Storm Elliott. Rather than rely on PAI incentives to provide assurance that generators would be ready for cold weather, PJM took direct steps to ensure a reliable outcome. The results of Polar Vortex 2025 vindicated PJM's strategy. PJM took conservative measures to ensure reliability by scheduling resources well in advance of the day-ahead energy market. PJM took additional advance actions to ensure transmission reliability. These commitments were not made to meet reserve requirements. Higher reserve requirements would not have addressed the Polar Vortex 2025 issues or cold weather reliability issues more generally.

The uplift associated with Polar Vortex 2025 was an expected outcome of conservative operations. This uplift is part of the way that PJM markets work and was the result of PJM's successful conservative operations approach to dealing with the cold weather risks of Polar Vortex 2025. PJM's commitment approach during Polar Vortex 2025 was significantly different than in 2024, for example. PJM committed only 1.4 percent of units on schedules less flexible than PLS during Polar Vortex 2025 compared to 17.2 percent during weather alert days in 2024. Nonetheless, improvements are needed to make the advance commitment process more predictable and transparent and to help ensure that these uplift charges are incurred only when needed for reliability.

4 Demand response payments are addressed in Section 6: Demand Response.

Overview

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $442.1 million, or 202.3 percent, in the first nine months of 2025 compared to the first nine months of 2024, from $218.5 million to $660.6 million.
- **Types of energy uplift credits.** In the first nine months of 2025, total energy uplift credits included $181.5 million in day-ahead generator credits, $447.7 million in balancing generator credits, $28.9 million in lost opportunity cost credits. Dispatch differential lost opportunity credits, which are a subset of balancing operating reserves, were implemented as part of fast start pricing on September 1, 2021, and were $2.0 million in the first nine months of 2025.
- **Types of units.** In the first nine months of 2025, steam coal units received 9.1 percent of day-ahead generator credits, and combustion turbines received 53.5 percent of balancing generator credits and 64.8 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 36.3 percent of dispatch differential lost opportunity credits, and hydro units received 47.5 percent of dispatch differential lost opportunity credits
- **Concentration of energy uplift credits.** In the first nine months of 2025, the top 10 units receiving energy uplift credits received 37.5 percent of all credits and the top 10 organizations received 70.3 percent of all credits.
- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $3.2 million, or 12.3 percent, in the first nine months of 2025, compared to the first nine months of 2024, from $25.7 million to $28.9 million.

  Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 65.2 percent of the $29.0 million of lost opportunity costs.
- **Following dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS

offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $17.9 million, of which PJM has resettled only $3.9 million, or 22.0 percent.

Energy Uplift Charges

- **Energy Uplift Charges.** In the first nine months of 2025, total energy uplift charges increased by $443.1 million, or 203.8 percent, compared to the first nine months of 2024, from $217.4 million to $660.6 million.
- **Types of Energy Uplift Charges.** In the first nine months of 2025, total uplift charges included $181.4 million in day-ahead operating reserve charges, $478.1 million in balancing generator charges, $0.6 million in reactive charges, and $0.4 million in black start services.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM require wind units to request CIRs based on the maximum output used in the ELCC calculation for wind units. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[5]

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market demand (VRR) curve. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result inflates uplift costs, suppresses energy prices, and is an incentive to inflexibility.

It is not appropriate to accept that inflexible units should be paid uplift based on inflexible offers. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to

5 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules. Such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift. There are defined steps that could and should be taken immediately to improve the modeling of combined cycle plants that do not require investment in combined cycle modeling software, including modeling soak time, and accurately accounting for transition times to power augmentation offer segments.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of fast start pricing. The same is true of PJM's proposals to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs creates a tradeoff between minimizing production costs and reduction of uplift. The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing approach.[6] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units routinely receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[7] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability by PJM in the day-ahead market.

Uplift payments could be significantly reduced by reversing many of the changes that have been made to the original basic uplift rules. The goal of uplift is to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, to operate at a loss. In the original PJM design, uplift was calculated on a daily basis, including all costs and net revenues. But that rule was changed to use only segments of the day. The result is to overstate uplift payments because units may be paid uplift for a day in which their net revenues exceed their costs. In the original PJM design, all net revenues from energy and ancillary services were an offset to uplift payments. That rule was changed to eliminate net revenue from the regulation market. The result is to overstate uplift payments, for no logical reason.

Uplift payments could also be significantly reduced to a more efficient level by eliminating all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units

6 Fast start pricing was approved by FERC and implemented on September 1, 2021. See 173 FERC ¶ 61,244 (2020).

7 On June 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280 (2019).

do not incur any costs to run and any revenue shortfalls are addressed by balancing generator credits.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch. PJM continues to pay uplift to units that do not follow dispatch. PJM and the MMU are actively working together to revise the definition of following dispatch to address these issues.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $17.9 million of incorrect uplift credits of which PJM has agreed and resettled only $3.9 million over the last two years, or 22.0 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases and generators offer to repay the credits.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

Polar Vortex 2025 resulted in 51.3 percent of uplift credits in the first nine months of 2025. This level of uplift was consistent with the efficient operation of a reliable market. In anticipation of the cold weather and to avoid a repetition of the poor performance during Winter Storm Elliott, PJM made out of market commitments to mitigate generation performance risks associated with cold temperatures and natural gas commodity illiquidity over the weekend and intraday. PJM took conservative measures to ensure reliability by scheduling resources well in advance of the day-ahead energy market. As there is no multiday market, out of market actions taken before the market starts generally result in uplift. While the results of the Polar Vortex 2025 vindicated PJM's strategy, the rules governing PJM's actions should be more transparent and clearly documented. The results of Polar Vortex 2025 are preferred to Winter Storm Elliott and increased uplift is the expected result. Nonetheless, the uplift rules need significant improvement. In addition, the process of conservative operations and advanced commitments needs to be improved, formalized, and made as market based as possible in order to minimize uplift.

Energy Uplift Credits

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. Energy uplift payments currently also result, incorrectly, from decisions by units to maintain an output level not consistent with PJM dispatch instructions. The resulting costs not covered by energy revenues are collected as energy uplift credits.

The day-ahead operating reserves category includes multiple credit types that are paid to resources cleared uneconomically in the day-ahead market. These resources include generators, imports, and load response.

The balancing operating reserves category includes multiple credit types based on the service provided by the resources. These credit types, paid to compensate for uneconomic generation in the balancing market, include generator credits, lost opportunity cost credits, dispatch differential lost opportunity cost credits, local constraint control credits, load response credits, import credits, and canceled resource credits. The largest credit type in the balancing operating reserves category is balancing generator credits. The reactive services category includes multiple credit types. Black start services credits exist to compensate resources for black start services in the day-ahead and balancing markets, as well as testing. Starting with this report, black start credits and local constraint credits are not broken out individually and are included in the category of balancing generator credits, matching PJM's Market Settlements Reporting System.

Table 4-1 shows the uplift totals for each credit category during the first nine months of 2024 and 2025.[8] In the first nine months of 2025, energy uplift credits increased by $442.1 million or 202.3 percent compared to the first nine months of 2024. PJM commitment and dispatch decisions associated with the 2025 Polar Vortex caused significant increases in day-ahead generator credits, balancing generator credits, and lost opportunity cost credits.

The dispatch differential lost opportunity cost is a credit that exists only as a result of fast start pricing. This credit is paid to flexible resources that are artificially dispatched down, to an output level below the level that is economic at fast start prices, in order to accommodate inflexible fast start resources. Fast start pricing was introduced on September 1, 2021.

Table 4-1 Energy uplift credits by category: January through September, 2024 and 2025[9]

Category	Type	(Jan - Sep) 2024 Credits (Millions)	(Jan - Sep) 2025 Credits (Millions)	Change	Percent Change	2024 Share	2025 Share
Day-Ahead	Generators	$93.8	$181.5	$87.7	93.5%	42.9%	27.5%
Balancing	Generators	$96.4	$447.7	$351.3	364.3%	44.1%	67.8%
	Canceled Resources	$0.1	$0.0	($0.1)	(74.8%)	0.0%	0.0%
	Lost Opportunity Cost	$25.7	$28.9	$3.2	12.3%	11.8%	4.4%
	Dispatch Differential Lost Opportunity Cost	$1.6	$2.0	$0.4	23.9%	0.7%	0.3%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Reactive Services	Generators	$0.9	$0.5	($0.4)	(41.2%)	0.4%	0.1%
	Lost Opportunity Cost	$0.0	$0.0	($0.0)	(85.0%)	0.0%	0.0%
	Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Condensing Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Total		$218.5	$660.6	$442.1	202.3%	100.0%	100.0%

8 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on October 10, 2025.
9 Year to year change is rounded to $0.01 million.

Categories of Credits and Charges

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Uplift credits paid to individual participants are paid for by charges to the groups of PJM market participants. The groups of participants charged varies depending on the type of uplift credit. For this reason, operating reserve charges do not always have the same value as operating reserve credits, since not all categories of uplift credits are paid for by the same PJM participants. For example, in the case of local constraint credits, credits are paid to generators in the form of balancing operating reserve credits but charges are allocated as local constraint charges. The same applies in the case of units scheduled day ahead for reactive support, for which the credits are paid in the form of day-ahead operating reserve credits but charges are allocated as reactive services charges. Table 4-2 and Table 4-3 show the categories of credits and charges and their relationships.

For example, in Table 4-2, day-ahead operating reserve credits for generators are paid for by day-ahead operating reserve charges. Those charges are paid for by market participants in proportion to their day-ahead load, day-ahead exports, and virtual transactions (DECs and UTCs). The charges are aggregated over the entire RTO region. Balancing generator reserve credits are paid for by two different types of charges: balancing operating reserve charges for reliability and balancing operating reserve charges for deviations. Charges for reliability are paid for by PJM members in proportion to their real-time load and real-time export transactions. Reliability charges are aggregated regionally over the entire RTO region, within the Western region, or within the Eastern region. Balancing operating reserve charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region, within the Western region, and within the Eastern region. Lost opportunity cost credits are paid for by balancing operating reserve charges for deviations. The charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region.

Starting with the *2024 Annual State of the Market Report for PJM*, black start credits and local constraint credits are not broken out individually and are included in the category of balancing generator credits. Similarly, cancellation charges, lost opportunity charges, and dispatch differential lost opportunity cost charges are not broken out individually and are included in the category of balancing generator charges.

Table 4-3 shows the relationship between credits and charges for resources providing reactive, synchronous condensing, and black start services. For example, the five sub-categories of reactive services credits (day-ahead operating reserves, generator, LOC, condensing, and synchronous condensing LOC) are paid by two different charge categories: reactive service charges and local constraint reactive services. The reactive service charges are paid by PJM members in proportion to their zonal real-time load, while the local constraint reactive service charges are paid for by transmission owners.

Table 4-2 Day-ahead and balancing operating reserve credits and charges

	Credit Category	Charges Category	Charge Responsibility	Geographic Charge Aggregation
DAY-AHEAD	Day-Ahead Operating Reserve Transaction	Day-Ahead Operating Reserves for Transactions	Day-Ahead Load, Day-Ahead Exports, DECs & UTCs	RTO Region
	Day-Ahead Operating Reserve Generator	Day-Ahead Operating Reserve for Generators		
	Day-Ahead Operating Reserves for Load Response	Day-Ahead Operating Reserve for Load Response		
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion	Unallocated Congestion		
BALANCING	Balancing Generator Reserves	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	RTO, Eastern, and Western Region
		Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Dispatch Differential Lost Opportunity Cost (DDLOC)	Balancing Operating Reserve for Deviations	Real-Time Load plus Real-Time Export Transactions	RTO Region
	Canceled Resources	Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Lost Opportunity Cost (LOC)			
	Real-Time Import Transactions			
	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Local Constraints Control	NA	Transmission Owner	NA

Table 4-3 Reactive services, synchronous condensing and black start services credits and charges

	Credits Category	Charges Category	Charge Responsibility
Reactive	Day-Ahead Operating Reserve	Reactive Services Charge	Zonal Real-Time Load
	Generator Reactive Services		
	LOC Reactive Services		
	Condensing Reactive Services	Local Constraint Reactive Services	Transmission owner
	Synchronous Condensing LOC Reactive Services		
Synchronous Condensing	Synchronous Condensing	Synchronous Condensing	Real-Time Load
	Synchronous Condensing LOC		Real-Time Export Transactions
Black Start	Day-Ahead Operating Reserve	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations
	Balancing Operating Reserve		
	Black Start Testing		
	Black Start LOC		

Types of Units

Table 4-4 shows the distribution of total energy uplift credits by unit type in the first nine months of 2025 and the first nine months of 2024. A combination of factors led to overall increased uplift payments, including unit specific issues and market issues of high fuel costs and PJM conservative operations during Polar Vortex 2025.

The longstanding rule which inexplicably exempted CTs from the otherwise generally applicable rules governing the payment of uplift credits was terminated effective November 1, 2022. Prior to November 1, CTs were paid uplift regardless of their output and regardless of whether they followed dispatch and as a result, CTs had no incentive to follow PJM dispatch signals.

Uplift credits paid to combustion turbines increased by $163.9 million or 168.7 percent during the first nine months of 2025 compared to the first nine months of 2024. In the first nine months of 2025, CTs received 64.8 percent of lost opportunity cost credits. Lost opportunity cost credits increased by $28.9 million or 12.3 percent compared to the first nine months of 2024.

Uplift credits paid to steam coal units increased by $3.8 million or 8.6 percent in the first nine months of 2025 compared to the first nine months of 2024. In the first nine months of 2025, day-ahead uplift credits in the PEPCO Zone made up 82.3 percent of total day-ahead uplift credits, and accounted for 135.3 percent of the increase in day-ahead uplift during the first nine months of 2025, primarily as a result of unit specific issues for the Chalk Point 3 and 4 units. In the first nine months of 2025, steam coal units in the BGE Zone received 91.5 percent of day-ahead uplift credits paid to steam coal units, primarily as a result of unit specific issues for the Brandon Shores 1 and 2 units.

Uplift credits paid to non-coal (gas or oil fired) steam units increased by $121.0 million or 190.6 percent in the first nine months of 2025 compared to the first nine months of 2024. In the first nine months of 2025, gas or oil fired steam units received $184.6 million, 27.9 percent of total credits, compared to $63.5 million, 29.1 percent of total credits, during the first nine months of 2024. In the first nine months of 2025, the day-ahead uplift paid to gas or oil fired steam units was 201.1 percent higher than during the first nine months of 2024, and accounted for 122.1 percent of the total increase in day-ahead operating reserves. The increase in day-ahead generator credits paid to gas or oil fired steam units in the PEPCO Zone accounted for 122.1 percent of the overall increase in day-ahead generator credits in the first nine months of 2025. In the PEPCO Zone, gas fired steam units Chalk Point 3 and 4 received $152.2 million in uplift in the first nine months of 2025.[10] During the 2025 Polar Vortex, non-coal steam units received $132.4 million, or 71.8 percent of all credits received by non-coal steam units during the first nine months of 2025. Non-coal steam units received 39.0 percent of total uplift credits during the 2025 Polar Vortex.

Uplift credits paid to combined cycle units increased by $146.9 million or 1,471.2 percent in the first nine months of 2025 compared to the first nine months of 2024. This increase occurred primarily in January 2025 as a result of the commitments made in advance of the day-ahead energy market during the 2025 Polar Vortex. The 2025 Polar Vortex accounted for 89.3 percent of the uplift credits paid to combined cycle units, and accounted for 51.3 percent of total uplift credits during the first nine months of 2025.

In the first nine months of 2025, uplift credits to wind units were $6.0 million, up by 346.1 percent compared to the first nine months of 2024.

Table 4-4 Total energy uplift credits by unit type: January through September, 2024 and 2025[11 12]

Unit Type	(Jan - Sep) 2024 Credits (Millions)	(Jan - Sep) 2025 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2024 Share	(Jan - Sep) 2025 Share
Combined Cycle	$10.0	$156.9	$146.9	1,471.2%	4.6%	23.7%
Combustion Turbine	$97.2	$261.1	$163.9	168.7%	44.5%	39.5%
Diesel	$1.4	$2.7	$1.2	87.0%	0.7%	0.4%
Hydro	$0.9	$0.9	$0.0	1.2%	0.4%	0.1%
Nuclear	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Solar	$0.2	$0.8	$0.6	226.9%	0.1%	0.1%
Steam - Coal	$43.9	$47.6	$3.8	8.6%	20.1%	7.2%
Steam - Other	$63.5	$184.6	$121.0	190.6%	29.1%	27.9%
Wind	$1.4	$6.0	$4.7	346.1%	0.6%	0.9%
Total	$218.5	$660.6	$442.1	202.3%	100.0%	100.0%

10 See Table 4-14.
11 Table 4-4 does not include balancing imports credits and load response credits in the total amounts.
12 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-5 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2025. The largest share of day-ahead credits, 97.5 percent, went to steam units. Steam units tend to be longer lead time units that are committed before the operating day. If a steam unit is needed for reliability and it is uneconomic, it will be committed in the day-ahead energy market and receive day-ahead uplift credits. The PJM market rules permit combustion turbines (CT), unlike other unit types, to be committed and decommitted in the real-time market. As a result of the rules and the characteristics of CT offers, CTs received 53.5 percent of balancing credits and 64.8 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may be paid balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines committed in the day-ahead market but not committed in real time receive lost opportunity credits to cover the profits they would have made had they operated in real time.

Table 4-5 Energy uplift credits by unit type: January through September, 2025

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Dispatch Differential Lost Opportunity Cost
Combined Cycle	1.3%	34.0%	0.0%	7.5%	1.0%	0.0%	18.2%
Combustion Turbine	1.2%	53.5%	0.0%	64.8%	22.9%	0.0%	18.1%
Diesel	0.0%	0.4%	0.0%	1.6%	74.3%	0.0%	0.3%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	47.5%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	2.8%	0.0%	0.0%	0.6%
Steam - Coal	9.1%	6.8%	0.0%	2.2%	1.9%	0.0%	9.8%
Steam - Other	88.4%	5.4%	100.0%	0.5%	0.0%	0.0%	1.8%
Wind	0.0%	0.0%	0.0%	20.6%	0.0%	0.0%	3.7%
Total (Millions)	$181.5	$447.7	$0.0	$28.9	$0.5	$0.0	$2.0

Day-Ahead Unit Commitment for Reliability

PJM can schedule units as must run in the day-ahead energy market that would otherwise not have been committed in the day-ahead market, when needed in real time to address reliability issues. Such reliability issues include thermal constraints, reactive transfer interface constraints, and reactive service.[13] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal. Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as self scheduled by a participant is not eligible for day-ahead operating reserve credits.[14]

Pool scheduled units are units that are committed in the day-ahead market based on economics. Units committed for reliability by PJM are units that are committed to satisfy reliability needs, regardless of whether the offers are economic. Self scheduled units are self committed by the generation owner and are not eligible for uplift. Pool scheduled units and units committed for reliability are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run in the day-ahead market and any revenue shortfalls are addressed by balancing operating reserve payments.

Balancing Uplift (Operating Reserve) Credits/ Balancing Generator Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover all of their operating costs from market revenues. Balancing operating reserves include multiple credit types that are paid to units in the balancing market, such as generator credits, lost opportunity cost credits, dispatch differential lost opportunity cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. Balancing generator credits are the largest category of balancing operating reserves. Balancing generator credits are calculated by hourly segments as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits but excluding regulation revenues) and its real-time

13 See OA Schedule 1 § 3.2.3(b).

14 See OA Schedule 1 § 3.2.3(a).

offer (startup, no load, and incremental energy offer). Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time are treated as new segments. Table 4-5 shows that combustion turbines (CTs) received 53.5 percent of balancing generator credits in the first nine months of 2025, or $239.7 million. Combined cycles (CCs) received 34.0 percent of balancing generator credits in the first nine months of 2025, or $152.0 million. During the 2025 Polar Vortex, the balancing generator credits to CCs exceeded CTs due to conservative operations commitments.

Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day. Uplift is also higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions. PJM apparently considers units that start when requested and turn off when requested to be operating as requested by PJM regardless of how well the units follow the dispatch signal.[15] Units should be disqualified from receiving uplift when the units do not follow dispatch instructions, block load or self schedule.

PJM's position on the payment of uplift is illogical and PJM's definition of units not operating as requested is illogical. The logical definition of operating as requested includes both start and shutdown when requested and that units follow their dispatch signal. Both should be required in order to receive uplift. Paying uplift to units not following dispatch does not provide an incentive for flexibility. The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch, instead of relying on PJM dispatchers' manual determinations, to evaluate eligibility for receiving balancing generator credits and for assessing generator deviations. As part of the metric, the MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.

15 *See* "Operating Reserve Make Whole Credit Education," slide 13, PJM presentation to the Market Implementation Committee. (April 13, 2022) <https://pjm.com/-/media/committees-groups/committees/mic/2022/20220413/item-11a---operating-reserve-make-whole-credits-education.ashx>.

Table 4-1 shows that balancing generator credits increased by 364.3 percent in the first nine months of 2025 compared to the first nine months of 2024.

CTs that operate on a day-ahead schedule tend to receive lower balancing generator credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units. The day-ahead model optimizes the system for all 24 hours, unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other). The shorter segments in real-time are defined by the minimum run time and allow for fewer offsets, resulting in greater amounts of uplift. Losses during the minimum run time segment are not offset by profits made in other segments on that day.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including differences in the hourly pattern of load, and differences in interchange transactions. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different optimization time periods used in the day-ahead and real-time markets.

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two scenarios.[16] The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to

16 Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

Table 4-6 shows monthly day-ahead and real-time LOC credits in 2024 and the first nine months of 2025. In the first nine months of 2025, LOC credits increased by $3.2 million or 12.3 percent compared to the first nine months of 2024. The overall change was an increase, which included a $3.6 million decrease in day-ahead LOC which was offset by a $6.7 million increase in real-time LOC.

In the first nine months of 2025, wind units received $6.0 million of uplift, up by $4.7 million compared to the first nine months of 2024. Wind units that are capacity resources are now required to procure Capacity Interconnection Rights (CIRs) equal to the maximum facility output included in the calculation of their ELCC value. Wind units that are capacity resources are paid uplift when PJM requests that the units reduce output below the maximum facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should use the lowest of the desired output, the estimated output based on actual wind conditions, or the capacity interconnection rights (CIRs) as the definition of the foregone opportunity.

Table 4-6 Monthly lost opportunity cost credits (Millions): 2024 and January through September, 2025[17 18]

	2024			2025		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.8	$0.2	$1.1	$2.6	$4.4	$7.0
Feb	$0.8	$0.1	$0.9	$0.1	$0.4	$0.5
Mar	$1.6	$0.2	$1.8	$0.7	$1.5	$2.1
Apr	$1.4	$0.7	$2.2	$1.1	$1.0	$2.1
May	$1.4	$0.5	$2.0	$2.0	$0.13	$2.2
Jun	$3.4	$0.5	$3.9	$5.5	$1.4	$7.0
Jul	$6.4	$0.2	$6.6	$2.4	$0.6	$3.1
Aug	$4.7	$0.8	$5.5	$1.7	$0.4	$2.1
Sep	$1.8	$0.2	$2.0	$2.8	$0.2	$2.9
Oct	$1.9	$0.3	$2.2			
Nov	$0.6	$0.3	$0.9			
Dec	$0.9	$1.5	$2.5			
Total (Jan - Sep)	$22.5	$3.4	$25.9	$18.9	$10.1	$29.0
Share (Jan - Sep)	86.9%	13.1%	100.0%	65.2%	34.8%	100.0%
Total	$26.0	$5.5	$31.5	$18.9	$10.1	$29.0
Share	82.4%	17.6%	100.0%	65.2%	34.8%	100.0%

17 Table 4-6 does not include pumped hydro lost opportunity cost credits in Real-Time Lost Opportunity Cost Credits.
18 Table 4-6 includes CT lost opportunity cost forfeiture in the Day-Ahead Lost Opportunity Cost. See "MSRS Report Format Documentation: CT Lost Opportunity Cost Forfeiture, version 5" for more details. <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/msrs-reports-documentation.aspx>

Energy Uplift Charges

Energy Uplift Charges

Table 4-7 shows that energy uplift charges for the first nine months of 2025 were $660.6 million, or 1.8 percent of total PJM billing.

Table 4-7 Total energy uplift charges: 2001 through September 2025

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.3%)	0.2%
2020	$90.9	$2.4	2.7%	0.3%
2021	$178.4	$87.5	96.3%	0.3%
2022	$284.5	$106.1	59.5%	0.3%
2023	$158.7	($125.8)	(44.2%)	0.3%
2024	$270.0	$111.3	70.1%	0.5%
2025 (Jan - Sep)	$660.6	$390.6	144.7%	1.8%

Table 4-8 shows total energy uplift charges by category for the first nine months of 2024 and 2025. The increase of $440.9 million is comprised of an $87.6 million increase in day-ahead uplift (operating reserve) charges, a $355.8 million increase in balancing generator charges, a $0.4 million decrease in reactive service charges, a $1.0 million decrease in synchronous condensing charges, and a $1.2 million decrease in local congestion charges. Starting with the *2024 Annual State of the Market Report for PJM*, cancellation charges, lost opportunity charges, and dispatch differential lost opportunity cost charges are not broken out individually and are included in the category of balancing generator charges, matching PJM's Market Settlements Reporting System.

Table 4-8 Total energy uplift charges by category: January through September, 2024 and 2025[19]

Category	(Jan - Sep) 2024 Charges (Millions)	(Jan - Sep) 2025 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$93.8	$181.4	$87.6	93.5%
Balancing Operating Reserves	$122.3	$478.1	$355.8	291.0%
Reactive Services	$1.0	$0.6	($0.4)	(41.4%)
Synchronous Condensing	$1.0	$0.0	($1.0)	(100.0%)
Black Start Services	$0.3	$0.4	$0.1	30.4%
Local Congestion Charges	$1.3	$0.1	($1.2)	(90.0%)
Total	$219.7	$660.6	$440.9	200.7%
Energy Uplift as a Percent of Total PJM Billing	0.6%	1.1%	0.8%	147.0%

19 The total PJM billing used in Table 4-8 is different from the total cost shown in Table 1-9. The total PJM billing in Table 4-8 represents the total dollars that pass through the PJM settlement process, while the total cost shown in Table 1-9 is the total cost to load and includes additional costs to load accounted for outside the PJM settlement process.

Table 4-9 compares monthly energy uplift charges by category for January 2024 through September 2025.

Table 4-9 Monthly energy uplift charges: January 2024 through September 2025

	2024 Charges (Millions)						2025 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total
Jan	$32.7	$23.9	$0.9	$0.2	$0.0	$57.7	$153.9	$245.8	$0.0	$0.1	$0.0	$399.8
Feb	$1.2	$5.4	$0.0	$0.0	$0.1	$6.8	$2.5	$32.50	$0.0	$0.0	$0.1	$35.2
Mar	$1.1	$10.8	$0.0	$0.0	$0.0	$12.0	$6.1	$28.58	$0.5	$0.0	$0.1	$35.3
Apr	$12.1	$19.3	$0.0	$0.1	$0.0	$31.5	$3.9	$36.62	$0.0	$0.0	$0.1	$40.6
May	$12.5	$21.0	$0.0	$0.0	$0.0	$33.6	$2.9	$16.64	$0.0	$0.0	$0.0	$19.6
Jun	$14.4	$12.6	$0.0	$1.0	$0.0	$28.1	$5.8	$31.76	$0.0	$0.0	$0.0	$37.6
Jul	$8.4	$11.5	$0.0	$0.0	$0.0	$19.9	$2.3	$46.08	$0.0	$0.0	$0.0	$48.4
Aug	$6.9	$10.9	$0.1	$0.0	$0.0	$17.9	$3.1	$24.06	$0.0	$0.0	$0.0	$27.1
Sep	$4.4	$6.9	$0.0	$0.0	$0.0	$11.3	$0.9	$16.07	$0.0	$0.0	$0.0	$17.1
Oct	$6.4	$9.0	$0.0	$0.0	$0.0	$15.4						
Nov	$3.2	$8.8	$0.0	$0.0	$0.1	$12.1						
Dec	$11.3	$12.1	$0.5	$0.0	$0.0	$23.9						
Total (Jan - Sep)	$93.8	$122.3	$1.0	$1.3	$0.3	$218.7	$181.4	$478.1	$0.6	$0.1	$0.4	$660.6
Share (Jan - Sep)	42.9%	55.9%	0.5%	0.6%	0.1%	100.0%	27.5%	72.4%	0.1%	0.0%	0.1%	100.0%
Total	$114.7	$152.0	$1.5	$1.3	$0.4	$270.0	$181.4	$478.1	$0.6	$0.1	$0.4	$660.6
Share	42.5%	56.3%	0.6%	0.5%	0.2%	100.0%	27.5%	72.4%	0.1%	0.0%	0.1%	100.0%

Table 4-10 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $355.9 million or 291.3 percent in the first nine months of 2025 compared to the first nine months of 2024.

Table 4-10 Balancing operating reserve charges: January through September, 2024 and 2025[20]

Category	(Jan - Sep) 2024 Charges (Millions)	(Jan - Sep) 2025 Charges (Millions)	Change	Percent Change	2024 Share	2025 Share
Balancing Operating Reserve Reliability Charges	$49.4	$327.3	$277.9	563.1%	40.4%	68.5%
Balancing Operating Reserve Deviation Charges	$72.9	$150.8	$77.9	106.8%	59.6%	31.5%
Balancing Operating Reserve Charges for Load Response			$0.0	NA	0.0%	0.0%
Balancing Local constraint Charges	$1.3	$0.1	($1.2)	(90.0%)	1.1%	0.0%
Total	$122.3	$478.1	$355.8	291.0%	100.0%	100.0%

20 Table 4-9 balancing operating reserve total does not match Table 4-10 because Table 4-10 does not include DDLOC charges of $1.6 million.

Uplift Eligibility

In PJM, units have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by generation owners. Table 4-11 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[21] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may be self scheduled in the day-ahead market and then be pool scheduled and dispatched in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are defined in the tariff as eligible for balancing operating reserve credits. However, in practice, units receive uplift credits when not following PJM's dispatch signal. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and unable to recover their operating cost for the day or segment.[22]

Energy Uplift Issues

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases.[24] Since 2018, the cumulative resettlement requests total $17.9 million, of which PJM has agreed and resettled only $3.9 million over the last two years, 22.0 percent, and 1.3 percent are waiting for a PJM response. The remaining 75.8 percent occurred prior to October 2023 and is subject to the OATT's limitation on claims. That limit does not apply and would not have applied if PJM informed the market participant within two years of the occurrence of the issue.[25] PJM should inform market participants of a potential issue when the MMU raises the issue with PJM and the market participant in order to ensure that the issues can be addressed. PJM has refused to accept the voluntary return of incorrectly paid uplift credits by generators when the MMU has identified such cases. The MMU continues to bring new cases to the attention of PJM.

Table 4-11 Dispatch status, commitment status and uplift eligibility[23]

		Commitment Status	
Dispatch Status	Dispatch Description	Self Scheduled (units committed by the generation owner)	Pool Scheduled and following PJM's dispatch signal (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Only eligible to receive LOC credits if dispatched down by PJM Eligible to set LMP	Eligible to receive uplift Eligible to set LMP

21 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
22 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.
23 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.
24 To date, the MMU has only requested resettlement of the most egregious cases.
25 OATT § 10.4.

The MMU identifies units that are not following dispatch and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved based on the real-time LMP, unit operating parameters (e.g. economic minimum, maximum and ramp rate) and energy offer.

Uplift Forfeiture Rule

The uplift forfeiture rule was introduced in 2000 after PJM observed that in the summer of 1999 units could circumvent the $1,000/MWh offer cap by submitting high offers associated with a long minimum run time (e.g. 24 hours). The rule states that units will not be paid operating reserve credits (uplift) when they are scheduled on their price-based offers during maximum generation conditions and their effective energy offer price exceeds $1,000 per MWh.[26] Maximum generation conditions include maximum generation emergencies, maximum generation emergency alerts, and when PJM schedules units based on the anticipation of a maximum generation emergency or maximum generation emergency alert.

In 2022 and 2023, PJM declared maximum generation conditions on five separate days. During these days, some units received uplift payments in violation of the uplift forfeiture rule. The five days in question are December 23 through 25 of 2022 (Winter Storm Elliott) and July 27 and 28 of 2023. The MMU has determined that, based on the uplift forfeiture rule, balancing operating reserves paid on December 23 and 24 of 2022 should be forfeited. PJM resettled the operating reserve credits paid to units that exceeded an effective offer price of $1,000 per MWh on December 23 and 24, 2022. The total balancing operating reserve credits returned totaled $1.7 million. In the first nine months of 2025, PJM declared maximum generation conditions for January 22, June 22-24, July 14-15, 23-24, and 27-29. The uplift forfeiture rule was triggered on June 23 and 24 because units received uplift with an effective energy price-based offer that exceeded $1,000 per MWh. The uplift payments under the uplift forfeiture rule on June 23 and 24 are under review.

26 See OA Schedule 1 Section 3.2.3 (m) Operating Reserves

The uplift forfeiture rule was also triggered on all of the maximum generation dates in July and analysis and results are pending.

Regulation Market Offsets

PJM does not include regulation market payments as an offset like other market revenues in the operating reserve calculations. Including regulation market revenues would result in lower uplift calculations. Table 4-12 shows that the regulation market revenues in the first nine months of 2025 were $111.5 million and that the balancing generator credits for those units receiving regulation revenues were $39.4 million. The table shows that if the regulation market revenues had been incorporated in the operating reserve calculation as an offset, the balancing generator payment for those units would have been $37.0 million instead of $39.4 million, 6.1 percent lower.

Table 4-12 Adjusted operating reserve credits: January through September, 2025

Month	Regulation Market Revenues (Millions)	Balancing Generator Credits (Millions)	Adjusted Balancing Generator Credits (Millions)	Difference
Jan	$19.8	$25.8	$25.1	($0.7)
Feb	$11.1	$3.4	$3.1	($0.3)
Mar	$11.0	$2.1	$1.8	($0.2)
Apr	$8.5	$2.8	$2.6	($0.2)
May	$8.7	$1.7	$1.5	($0.2)
Jun	$16.5	$1.3	$1.1	($0.2)
Jul	$14.4	$1.3	$0.9	($0.3)
Aug	$9.8	$0.4	$0.3	($0.1)
Sep	$11.8	$0.6	$0.5	($0.1)
Total	$111.5	$39.4	$37.0	($2.4)

Concentration of Energy Uplift Credits

The recipients of uplift payments are highly concentrated by unit and by company. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that a lack of full transparency has made it more difficult for competition to affect these payments.[27] Table 4-13 shows the concentration of energy uplift credits. The top 10 units received 37.5

27 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits paid on and after July 1, 2019, on September 10, 2019.

percent of total energy uplift credits in the first nine months of 2025. The top 10 companies received 70.3 percent of total energy uplift credits in the first nine months of 2024.

Table 4-13 Top 10 units and organizations energy uplift credits: January through September, 2025

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$175.6	96.8%	$10.1	5.6%
Balancing	Canceled Resources	$0.0	100.0%	$0.0	100.0%
	Generators	$88.0	19.7%	$284.5	63.5%
	Lost Opportunity Cost	$6.4	22.2%	$19.7	68.3%
	Dispatch Differential Lost Opportunity Cost	$1.0	50.3%	$1.6	79.9%
	Total Balancing	$95.4	19.9%	$305.8	63.9%
Reactive Services		$0.5	95.3%	$0.5	100.0%
Total		$247.5	37.5%	$464.7	70.3%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-14 through Table 4-18 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Chalk Point 3 and 4 are non-coal steam units in the PEPCO Zone with an ICAP of 582 MW each. In the first nine months of 2025, the Chalk Point 3 and 4 units received a combined $152.2 million in uplift, 23.0 percent of total uplift payments. In the first nine months of 2024, the Chalk Point 3 and 4 units received a combined $32.4 million in uplift, 14.8 percent of total uplift payments.

Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 submitted retirement notifications to PJM and the MMU in April and October of 2023. Brandon Shores 1 and 2 are coal units in BGE with an ICAP of 635 MW and 638 MW. Wagner 3 and 4 are oil units in BGE with an ICAP of 305 MW and 397 MW. PJM determined that these resources were needed for reliability until transmission upgrades can be completed. In the first nine months of 2025, the Brandon Shores 1 and 2 units received a combined $37.4 million in uplift, 5.7 percent of total uplift payments.

Table 4-14 Top 10 recipients of total uplift: January through September, 2025

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	PEP CHALKPOINT 4 F	PEPCO	$110,814,172	16.8%
2	PEP CHALKPOINT 3 F	PEPCO	$41,386,017	6.3%
3	BC BRANDON SHORES 2 F	BGE	$18,847,115	2.9%
4	BC BRANDON SHORES 1 F	BGE	$18,525,145	2.8%
5	JC REDOAK 1 CC	JCPL	$13,769,290	2.1%
6	PS NEWARK ENERGY CENTER 10 CC	PSEG	$12,363,576	1.9%
7	BC WAGNER 3 F	BGE	$10,210,854	1.5%
8	ME IRONWOOD 1 CC	METED	$8,396,334	1.3%
9	ACE WEST DEPTFORD CROWN POINT 1 CC	AECO	$6,800,396	1.0%
10	DPL WILDCAT POINT 1 CC	DPL	$6,413,402	1.0%
Total of Top 10			$247,526,300	37.5%
Total Uplift Credits			$660,596,000	100.0%

Table 4-15 Top 10 recipients of day-ahead generation credits: January through September, 2025

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	PEP CHALKPOINT 4 F	PEPCO	$107,440,083	59.2%
2	PEP CHALKPOINT 3 F	PEPCO	$40,904,824	22.5%
3	BC BRANDON SHORES 2 F	BGE	$8,600,781	4.7%
4	BC BRANDON SHORES 1 F	BGE	$6,488,927	3.6%
5	AEP CLINCH RIVER 2 F	AEP	$3,326,932	1.8%
6	BC WAGNER 3 F	BGE	$3,325,484	1.8%
7	AEP CLINCH RIVER 1 F	AEP	$3,168,887	1.7%
8	BC WAGNER 4 F	BGE	$1,462,385	0.8%
9	PEP PANDA 1 F	PEPCO	$434,906	0.2%
10	PEP PANDA 2 F	PEPCO	$433,590	0.2%
Total of Top 10			$175,586,799	96.8%
Total day-ahead operating reserve credits			$181,461,608	100.0%

Table 4-16 Top 10 recipients of balancing generator credits: January through September, 2025

Rank	Unit Name	Zone	Balancing Generator Credits	Share of Balancing Generator Credits
1	JC REDOAK 1 CC	JCPL	$13,763,614	7.6%
2	PS NEWARK ENERGY CENTER 10 CC	PSEG	$12,321,746	6.8%
3	BC BRANDON SHORES 1 F	BGE	$12,035,587	6.6%
4	BC BRANDON SHORES 2 F	BGE	$10,245,746	5.6%
5	ME IRONWOOD 1 CC	METED	$8,395,410	4.6%
6	BC WAGNER 3 F	BGE	$6,866,864	3.8%
7	ACE WEST DEPTFORD CROWN POINT 1 CC	AECO	$6,796,114	3.7%
8	PE PHILLIPS ISL LINWOOD 1 CC	PECO	$6,271,104	3.5%
9	DPL WILDCAT POINT 1 CC	DPL	$6,134,832	3.4%
10	COM 929 JACKSON 2 CC	COMED	$5,182,140	2.9%
Total of Top 10			$88,013,156	48.5%
Total balancing operating reserve credits			$447,746,059	100.0%

Table 4-17 Top 10 recipients of lost opportunity cost credits: January through September, 2025

Rank	Unit Name	Zone	Lost Opportunity Cost Credits	Share of Lost Opportunity Cost Credits
1	PEP DICKERSON H 1 CT	PEPCO	$1,266,130	4.4%
2	PEP DICKERSON H 2 CT	PEPCO	$888,861	3.1%
3	AEP FOX SQUIRREL 1 SP	AEP	$592,061	2.1%
4	COM BRIGHT STALK 1 WF	COMED	$581,734	2.0%
5	COM BLOOMING GROVE 1 WF1	COMED	$550,908	1.9%
6	VP REMINGTON 4 CT	DOM	$532,706	1.8%
7	COM HIGH TRAIL 1 WIND	COMED	$532,461	1.8%
8	COM LEE DEKALB 1 WF	COMED	$500,000	1.7%
9	DPL ROCK SPRINGS 2 CT	DPL	$497,518	1.7%
10	COM CAYUGA RIDGE 1 WF	COMED	$478,783	1.7%
Total of Top 10			$6,421,161	22.2%
Total lost opportunity cost credits			$28,874,394	100.0%

Table 4-18 Top 10 recipients of dispatch differential lost opportunity cost credits: January through September, 2025

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credits	Share of Dispatch Differential Lost Opportunity Cost Credits
1	AEP SMITH MOUNT 1-5 H	AEP	$245,264	12.5%
2	VP GASTON 1-4 H	DOM	$204,682	10.5%
3	VP KERR DAM 1-7 H	DOM	$158,548	8.1%
4	AP BATH COUNTY 1-6 H	DOM	$119,378	6.1%
5	VP BATH COUNTY 1-6 H	DOM	$92,080	4.7%
6	JC YARDS CREEK 1-3 H	JCPL	$73,521	3.8%
7	VP MARSHRUN 1 CT	DOM	$25,320	1.3%
8	VP MARSHRUN 3 CT	DOM	$22,398	1.1%
9	PEP ST CHARLES-KELSON RIDGE 2 CC	PEPCO	$21,543	1.1%
10	AEP MOUNTAINEER 1 F	AEP	$21,372	1.1%
Total of Top 10			$984,106	50.3%
Total dispatch differential lost opportunity cost credits			$1,956,323	6.8%

Uplift Credits and Market Power Mitigation

Absent effectively implemented market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local structural market power in the energy market.[28] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power to their cost-based offer. Offer capping is designed to set offers at competitive levels.

Table 4-19 shows day-ahead operating reserve credits paid to committed and dispatched units called on during the first nine months of 2025, classified by commitment schedule type. Units using parameter limited schedules received $113.1 million or 62.3 percent of day-ahead operating reserve credits in the first nine months of 2025, units using price-based offers received $30.3 million or 16.7 percent, and units using cost-based offers received $38.1 or 21.0 percent.

Table 4-19 Day-ahead operating reserve credits by Offer Type: January through September, 2025

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Share of DAOR
Cost	$38.1	21.0%
Price	$30.3	16.7%
PLS	$113.1	62.3%
Total	$181.5	100.0%

Table 4-20 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. On weather alert days, PJM can require the use of parameter limited schedules (PLS) to prevent the exercise of market power through the use of inflexible parameters. Of all the day-ahead credits received during days with weather alerts, 1.1 percent went to units that were committed on cost schedules, which are parameter limited, 97.3 percent went to units that were committed on price PLS schedules and 1.5 percent went to units committed on price schedules less flexible than PLS. These results indicate a significant change in PJM's commitment approach during weather alerts. PJM committed only 1.5 percent of units on schedules less flexible than PLS during weather

28 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

alert days in 2025 compared to 17.2 percent during weather alert days in 2024.

Table 4-20 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through September, 2025

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during emergency alerts
Committed on cost (cost capped)	$1,267,761	1.1%
Committed on price schedule as flexible as PLS	$59,921	0.1%
Committed on price schedule less flexible than PLS	$1,775,677	1.5%
Committed on price PLS	$113,117,800	97.3%
Total	$116,221,159	100.0%

Gas fired generators may request temporary exceptions to parameter limits such as minimum run time based on restrictions imposed by natural gas pipelines, including ratable takes.[29] Table 4-21 shows the day-ahead operating reserve uplift credits received from 2018 through the first nine months of 2025 by units that submitted parameter exception requests for a 24 hour minimum run time based on gas pipeline restrictions. In the first nine months of 2025, 93 units requested an exception for a 24 hour minimum run time and 60 units received uplift payments amounting to $147.7 million of day-ahead operating reserves and $30.9 million in balancing operating reserves, or 81.4 percent of total day-ahead operating reserves and 6.9 percent of total balancing operating reserves, corresponding to 22.4 percent and 4.7 percent of total uplift.

Table 4-21 Uplift credits for units with 24 hour minimum run times due to gas pipeline restrictions: 2018 through September 2025

Year	Day-Ahead Operating Reserve Credits (Millions)	Balancing Generator Credits (Millions)	Number of Units with 24 Hour Min Run Time Exceptions	Number of Units with 24 Hour Min Run Time Exceptions that Received Uplift
2018	$4.9	$0.7	25	2
2019	$0.2	$0.6	37	12
2020	$0.2	$0.2	13	2
2021	$0.7	$0.6	61	42
2022	$14.4	$9.8	81	38
2023	$10.7	$1.5	75	23
2024	$30.2	$2.4	79	41
2025 (Jan - Sep)	$147.7	$30.9	93	60

Polar Vortex 2025 (January 19 – 23, 2025)

The commitment and dispatch of units by PJM during Polar Vortex 2025 (January 19 through 23, 2025), resulted in significant uplift payments Table 4-22 summarizes the uplift payments by category during Polar Vortex 2025. During Polar Vortex 2025, generating units received $125.8 million in day-ahead operating reserve credits, 69.3 percent of total day-ahead operating reserves during the first nine months of 2025, and 37.1 percent of total uplift during Polar Vortex 2025. During Polar Vortex 2025, generating units received $207.6 million in balancing generator credits, 46.4 percent of total balancing generator credits during the first nine months of 2025 and 61.2 percent of total uplift during Polar Vortex 2025. Total uplift payments during Polar Vortex 2025 were $339.1 million, 51.3 percent of total uplift during the first nine months of 2025.

29 See OA Schedule 1 Section 6.6 (C) Minimum Generator Operating Parameters – Parameter Limited Schedules.

Table 4-22 Energy uplift credits by category during Polar Vortex 2025

Category	Type	2025 Polar Vortex Credits (Millions)	(Jan - Sep) 2025 Credits (Millions)	Polar Vortex Share of uplift (Jan - Sep) 2025	Share of Polar Vortex Uplift
Day-Ahead	Generators	$125.8	$181.5	69.3%	37.1%
Balancing	Generators	$207.6	$447.7	46.4%	61.2%
	Canceled Resources	$0.0	$0.0	0.0%	0.0%
	Lost Opportunity Cost	$5.7	$28.9	19.6%	1.7%
	Dispatch Differential Lost Opportunity Cost	$0.1	$2.0	3.0%	0.0%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	NA	0.0%
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	NA	0.0%
Reactive Services	Generators	$0.0	$0.0	NA	0.0%
	Lost Opportunity Cost	$0.0	$0.5	0.0%	0.0%
	Condensing	$0.0	$0.0	0.0%	0.0%
	Condensing Lost Opportunity Cost	$0.0	$0.0	NA	0.0%
Total		$339.1	$660.6	51.3%	100.0%

Uplift during Polar Vortex 2025 was a result of out of market commitments made by PJM in anticipation of the cold weather. PJM committed units on Friday, January 17 for the January 19, 20 and 21 operating days. These commitments were made in advance of the Day-Ahead Energy Market, before offers were due. Some of the units cleared the Day-Ahead Energy Market economically and did not require uplift payments because their offers were covered by the day-ahead LMP. The rest of the units committed in advance that did not clear the Day-Ahead Market received balancing operating reserves credits because their offers were not covered by the real-time LMP. PJM made these commitments to mitigate generator performance risks based on available information about startup and operating uncertainty due to expected cold temperatures and gas supply illiquidity, including the need for 24 hour minimum run times to meet pipeline requirements for ratable takes.[30] PJM also committed specific units in advance to ensure transmission system reliability. That information was available because in 2024, in order to improve preparations for cold weather, PJM requested that all generators provide their cold weather operating limits, including the operating temperature limit (i.e. lowest ambient temperature at which the plant was designed to operate reliably) and starting temperature limit (i.e. lowest ambient temperature at which the plant could reliably start).

As a result of the low temperatures expected on Monday, January 20 and subsequent days, PJM committed units before temperatures reached the expected low levels. On Friday, January 17 natural gas traded for multiple days, referred to as the weekend package. The weekend package included gas days January 18, 19, 20 and 21, covering the period from Saturday, January 18, 10:00 to Wednesday, January 21, 10:00. PJM committed units on Friday to ensure that they could procure gas over the period of weekend package, reducing the risks of not being able to procure gas during individual days. The same actions were taken on Tuesday, January 21 for gas day January 22 (which covered the period from Wednesday, January 22, 10:00 to Thursday, January 23, 10:00).

The out of market commitments resulted primarily from conservative operations, which PJM declared from January 20 through January 23, but also included unit commitments for transmission constraints.[31] These commitments were made to ensure that supply that in previous events had performed poorly due to cold temperatures and gas supply issues, did not face the same risks. These commitments were not made to meet reserve requirements.

The day-ahead operating reserve credits were the result of units committed for transmission reliability in the day-ahead market (rather than conservative operations), these payments were made to a very small number of units.

Balancing operating reserve credits were the result of multiday commitments to minimize generation performance risk under conservative operations. Those units, mostly gas-fired combined cycle units, were committed ahead of time but did not clear the day-ahead market.

30 *See* "Winter Storm Gerri Review January 13–22, 2024," PJM presentation to the Operating Committee. (February 8, 2024) <https://www.pjm.com/-/media/committees-groups/committees/oc/2024/20240208/20240208-item-11---cold-weather-update.ashx>.

31 See PJM "Manual 13: Emergency Operations," Section 3.2 Conservative Operations Rev. 95 (Feb. 20, 2025).

Table 4-23 summarizes the total energy uplift credits by unit type during Polar Vortex 2025. Combined cycles received $140.1 million in uplift payments, non-coal steam units received $132.4 million and combustion turbines received $63.0 million.

Table 4-23 Total energy uplift credits by unit type during the 2025 Polar Vortex

Unit Type	2025 Polar Vortex Credits (Millions)	(Jan - Sep) 2025 Credits (Millions)	Polar Vortex Share of Uplift (Jan - Sep)	Share of Polar Vortex Uplift
Combined Cycle	$140.1	$156.9	89.3%	41.3%
Combustion Turbine	$63.0	$261.1	24.1%	18.6%
Diesel	$0.4	$2.7	13.4%	0.1%
Hydro	$0.0	$0.9	0.3%	0.0%
Nuclear	$0.0	$0.0	0.0%	0.0%
Solar	$0.0	$0.8	0.0%	0.0%
Steam - Coal	$0.2	$47.6	0.3%	0.0%
Steam - Other	$132.4	$184.6	71.8%	39.0%
Wind	$3.1	$6.0	51.0%	0.9%
Total	$339.1	$660.6	51.3%	100.0%

PJM chose to prepare for the weather related risks of Polar Vortex 2025 in very different ways than for Winter Storm Elliott. Rather than rely on PAI incentives to provide assurance that generators would be ready for cold weather, PJM took direct steps to ensure a reliable outcome. The results of Polar Vortex 2025 vindicated PJM's strategy. PJM took conservative measures to ensure reliability by scheduling resources well in advance of the day-ahead energy market. PJM took additional advance actions to ensure transmission reliability. As there is no multiday market, out of market actions taken before the market starts generally result in uplift. Based on this experience, the rules governing PJM's actions should be more transparent and clearly documented, including defined criteria for taking such actions. In addition, there should be rules about energy offers used for these commitments, and uplift rules should be revised to account for the multiday nature of these commitments. The lessons learned include that conservative operations are preferred to the Winter Storm Elliott approach of assuming that generators would respond, that increased uplift is the expected result and that the process of conservative operations and advance commitments needs to be improved, formalized and made as market oriented as possible in order to minimize uplift and make it as predictable as possible.

Summer Heat Waves in 2025

During the June Heat Wave, lasting June 22 - 26, generating units received $5.8 million in balancing generator credits, 1.3 percent of total balancing generator credits during the first nine months of 2025, and 54.8 percent of total uplift during the June Heat Wave. During the June Heat Wave, generating units received $4.0 million in lost opportunity cost credits, 13.7 percent of total lost opportunity cost credits during the first nine months of 2025 and 37.2 percent of total uplift during the June Heat Wave. Total uplift payments during the June Heat Wave were $10.6 million, 1.6 percent of total uplift during the first nine months of 2025. Of the balancing operating reserve credits during the June Heat Wave, which totaled $5.8 million, $3.1 million was paid to combustion turbines and diesels, $2.6 million was paid to steam units, and $0.9 million was paid to combined cycle units. Of the lost opportunity costs credits paid during the June Heat Wave, which totaled $4.0 million, $3.0 million was paid to flexible resources scheduled day ahead and not committed in real time for the full day-ahead schedule and $1.0 million was paid to units manually dispatched down.

PJM experienced multiple heat waves in July, resulting in periods of high demand, specifically July 14-17 and 23-30. Uplift credits during those days accounted for 6.0 percent of the increase in uplift credits during the first nine months of 2025 compared to the first nine months of 2024.

Capacity Market

In PJM, the capacity market exists to make the energy market work. Energy powers lights and computers and air conditioners. Capacity does not power anything. The capacity market needs to define the total MWh of energy that are needed to reliably serve load. The capacity market needs to provide the missing money. A primary reason to have a capacity market is that the energy market does not provide adequate net revenues to provide incentives for entry and for maintaining existing units. The obligation of load serving entities (LSEs) to own capacity equal to the peak demand plus a reserve margin was a longstanding feature of the PJM Operating Agreement before the creation of the PJM markets. The initial impetus to a capacity market in PJM, a request by the Pennsylvania PUC, was to support retail competition by ensuring that small new entrant competitive LSEs would have access to capacity at a competitive price without having to build capacity or purchase capacity bilaterally from incumbent generation owners at monopoly prices. The first, the daily capacity market, created in 1999, was replaced in 2007 by the current design based on the recognition that the energy market resulted in a shortfall in net revenues compared to that necessary to attract and retain adequate resources for the reliable operation of the energy market. The exogenous reliability requirement to have a level of capacity in excess of the level that would result from the operation of an energy market alone reduces the level and volatility of energy market prices and reduces the duration of high energy market prices. This reduces net revenue to generation owners which reduces the incentive to invest. In order for the PJM markets to be self sustaining, the net revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy and ancillary services markets.

The only goal of the detailed design of the capacity market is to ensure that the opportunity for that revenue equilibration exists through a competitive process.

The Capacity Performance (CP) design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market.

PJM's introduction of its significantly modified ELCC method in the 2025/2026 BRA was another radical change to the capacity market design. While it is a good idea to evaluate unit specific performance and a good idea to recognize that risk occurs in the winter as well as the summer and that risks may be correlated, ELCC was implemented before it could be fully tested and unintended consequences evaluated. The results of the 2025/2026 BRA illustrate the extreme sensitivity of the market outcomes to a range of assumptions and decisions about market design details that were not adequately tested or reviewed with stakeholders.[1]

The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

The PJM market design is based on the must offer and must buy obligations of capacity resources. All capacity resources are required to offer into the capacity auctions. The categorical exemption for intermittent resources, capacity storage resources, and hybrid resources from the RPM must offer requirement was eliminated for all resources except demand resources in February 2025.[2] All LSEs must buy capacity equal to their peak load plus a reserve margin.

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay

1 The MMU prepared a series of reports on the 2025/2026 BRA results which can be found here: <https://www.monitoringanalytics.com/reports/Reports/2024.shtml> and here <https://www.monitoringanalytics.com/reports/Reports/2025.shtml>
2 FERC approved extending the RPM must offer requirement to intermittent resources, capacity storage resources, and hybrid resources but not to demand resources on February 20, 2025. 190 FERC ¶ 61,117.

the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

There are significant market design issues in the PJM Capacity Market that currently prevent the market from achieving competitive results.

One of the most important issues currently facing the PJM Capacity Market is the addition of data center load. The MMU concludes that the failure to recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed. PJM should not simply permit the interconnection of large data center loads if it cannot do so reliably, with adequate generation capacity to meet those loads.

The Market Monitoring Unit (MMU) analyzed market design, market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[3] The conclusions are a result of the MMU's evaluation of the 2026/2027 Base Residual Auction.[4] [5] [6] [7] [8] [9] [10] [11]

3 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
4 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>.
5 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf>.
6 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf>.
7 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part D," (December 6, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf>.
8 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part E," (January 31, 2025). <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_E_20250131.pdf>.
9 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part F," (February 4, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_F_20250204.pdf>.
10 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," (June 3, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf>.
11 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.

Table 5-1 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM Capacity Market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[12] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[13]
- Participant behavior was evaluated as not competitive in the 2026/2027 BRA. Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[14] The offers in the 2026/2027 BRA included those based on standalone CPQR offer caps. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.

12 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. In the 2023/2024 RPM Third Incremental Auction, 36 participants in the RTO passed the TPS test.
13 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.
14 190 FERC ¶ 61,117 (2025).

- Market performance was evaluated as not competitive based on the 2026/2027 Base Residual Auction as a result of the flaws in the Effective Load Carrying Capability (ELCC) design including the failure to correctly define the reliability contribution of thermal resources in the winter, and the failure to recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed.
- Market design was evaluated as mixed because while there are many positive features of the capacity market design and some of the MMU's recommendations were implemented in the 2026/2027 BRA, there are several features of the RPM design which still threaten competitive outcomes. These include the lack of a queue for the addition of large new data center loads, details of PJM's ELCC implementation, the definition of market seller offer caps, the failure to apply the RPM must offer requirement to demand resources, the inclusion of performance assessment interval (PAI) penalties, the use of gross CONE as the maximum price on the VRR curve, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.[15]

15 While PJM filed for and FERC accepted the inclusion of RMR resources Brandon Shores and Wagner plants in the 2026/2027 BRA and 2027/2028 BRA, that does not require that RMR resources be included in capacity market auction clearing in future auctions for these or other RMR resources. See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a three year forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.[16] PJM introduced the Capacity Performance design for the 2017/2018 BRA. PJM introduced a new ELCC method for defining capacity MW offered in the 2025/2026 BRA.[17]

Under RPM, capacity obligations are annual.[18] By design, Base Residual Auctions (BRA) are held for delivery years that are three years in the future despite recent auction delays. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[19] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year although some incremental auctions have not been held as a result of delays in holding BRAs.[20] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[21] A Reliability Backstop Auction may be conducted if tariff defined criteria are met to resolve reliability criteria violations caused by lack of sufficient capacity procured through RPM auctions.[22] If the installed reserve margin resulting from the total UCAP committed through self supply or BRAs for three consecutive years is more than one percentage point lower than the approved PJM installed reserve margin, PJM will make a filing with FERC to conduct a Reliability Backstop Auction. If the total UCAP committed

16 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
17 See 186 FERC ¶ 61,080 (2024), *reh'g order*, 189 FERC ¶ 61,043 (2024).
18 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
19 See 126 FERC ¶ 61,275 at P 86 (2009).
20 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
21 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
22 See OATT Attachment DD § 16.

for all base load generation resources in BRAs for three consecutive years is less than the forecasted minimum hourly load, PJM will make a filing with FERC to conduct a Reliability Backstop Auction.

The 2025/2026 RPM Third Incremental Auction and the 2026/2027 RPM Base Residual Auction were conducted in the first nine months of 2025.

Market Structure

- **RPM Installed Capacity.** In the first nine months of 2025, RPM installed capacity increased 2,072.3 MW or 1.2 percent, from 179,656.2 MW on January 1, to 181,728.5 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** Total reserves on June 1, 2025, were 19,999.9 MW, which is 205.1 MW (UCAP) short of the required reserve level of 20,205.0 MW (UCAP). On June 1, 2025, the target installed reserve margin was 17.8 percent, and the actual reserve margin was only 17.6 percent.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2025, 48.9 percent was gas; 20.7 percent was coal; 17.7 percent was nuclear; 4.5 percent was hydroelectric; 2.2 percent was oil; 1.2 percent was wind; 0.3 percent was solid waste; and 4.4 percent was solar.
- **Market Concentration.** In the 2025/2026 RPM Third Incremental Auction and the 2026/2027 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[23] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[24] [25] [26]

23 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).
24 See OATT Attachment DD § 6.5.
25 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
26 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

- **Imports and Exports.** Of the 1,281.7 MW of imports offered in the 2026/2027 RPM Base Residual Auction, 1,281.7 MW cleared. Of the cleared imports, 697.4 MW (54.4 percent) were from MISO.
- **Demand Resources.** Committed DR was 5,782.9 MW for June 1, 2025, as a result of cleared capacity for demand resources in RPM auctions for the 2025/2026 Delivery Year (6,265.9 MW) less replacement capacity (483.0 MW).
- **Energy Efficiency Resources.** EE is not a capacity resource but is paid the capacity market clearing price as a subsidy through the 2025/2026 Delivery Year. Committed EE was 1,481.6 MW for June 1, 2025, as a result of MW offered at a price less than or equal to the RPM auction clearing price in RPM auctions for the 2025/2026 Delivery Year (1,493.2 MW) less replacement MW (11.6 MW).

Market Conduct

- **2025/2026 RPM Third Incremental Auction.** Of the 307 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for two generation resources (0.7 percent).
- **2026/2027 RPM Base Residual Auction.** Of the 1,293 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for 82 generation resources (6.3 percent).

Market Performance

- The 2025/2026 RPM Third Incremental Auction and the 2026/2027 RPM Base Residual Auction were conducted in the first nine months of 2025. The weighted average capacity price for the 2025/2026 Delivery Year is $296.98 per MW-day, including all RPM auctions for the 2025/2026 Delivery Year. The weighted average capacity price for the 2026/2027 Delivery Year is $329.17 per MW-day, including all RPM auctions for the 2026/2027 Delivery Year.
- For the 2025/2026 Delivery Year, RPM annual charges to load are $14.8 billion.

- In the 2026/2027 RPM Base Residual Auction, the market performance was determined to be not competitive.

Part V Reliability Service (RMR)

- Of the nine companies (28 units) that have provided service following deactivation requests, two companies (seven units) filed to be paid under the deactivation avoidable cost rate (DACR), the formula rate. The other seven companies (21 units) filed to be paid under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first nine months of 2025 was 6.6 percent, an increase from 4.5 percent in the first nine months of 2024.[27]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first nine months of 2025 was 83.7 percent, a decrease from 86.3 percent in the first nine months of 2024.

Recommendations[28]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, and imports.[29] [30] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market construct because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 delivery year. EE is not a capacity resource as defined in the tariff, and there is no reason to continue to pay large subsidies to EE providers.[31] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[32]
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs to intermittent resources that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[33]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU

27 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on October 22, 2025. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

28 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

29 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

30 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

31 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 37 (Dec. 18, 2024).

32 See 189 FERC ¶ 61,095 (2024).

33 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

recommendation that all capacity resources have a must offer obligation in the capacity market auctions. (Priority: High. First reported 2023. Status: Partially adopted.)

- The MMU recommends that PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. (Priority: High. First reported 2023. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement in the 2022 Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as 1.5 times Net CONE, capped at Gross CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the gross CONE in ICAP terms for a CT to the gross CONE in UCAP terms be the ELCC based on winter ratings. (Priority: High. First reported 2024. Status: Adopted 2025.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model including transmission constraints inside LDAs. The market design should clear and pay units that are needed for reliability per PJM's transmission reliability analysis in order to forestall RMRs. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system inside and outside LDAs consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)[34]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding

34 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)[35]
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that modifications to existing resources, including relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[36]
- The MMU recommends that the RPM market power mitigation rules be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive

35 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

36 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity for both new resources and existing resources. (Priority: Medium. First reported 2017. Status: Not adopted.)[37]

- The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[38] (Priority: High. First reported 2013. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage and associated performance penalty. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined to reflect seasonal extreme conditions. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or subzonal, or defined combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

37 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

38 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from the current one quarter prior (See Table 5-29) to 12 months prior to an auction in which the unit will not be offered due to deactivation; and no less than 12 months prior to the date of deactivation (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends elimination of both the cost of service recovery rate option and the deactivation avoidable cost rate option for providing Part V reliability service (RMR), and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus a defined incentive. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that if units that are paid under Part V of the OATT (RMR) are included in the calculation of CETO and/or reliability in the relevant LDA, the capacity of the RMR resources should also be included in capacity market supply at zero cost, but without all the obligations of a capacity resource, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions, until a decision is made to build transmission as a replacement, and then should be included. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate timely and competitive entry into the PJM markets, open access to the transmission system and maintain the priority order defined by the queue process. (Priority: High. First reported 2023. Status: Not adopted.)

Conclusion

The analysis of the PJM Capacity Market begins with market design and market structure, which provide the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market design and market structure. Regardless of the ownership structure of a market, the market design can result in noncompetitive outcomes. In a good market design and a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power like the PJM Capacity Market, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. The analysis also examines the impact of market design choices on market performance.

The MMU concludes that the results of the 2026/2027 RPM Base Residual Auction were significantly affected by flawed market design elements including the lack of a queue for the addition of large new data center loads, by the performance assessment interval (PAI) penalties that are part of the CP design, by PJM's ELCC approach, by the definition of market seller offer caps, by the failure to extend the RPM must offer requirement to demand resources, and by the product definition and lack of market power mitigation for demand resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. PJM filed changes that were approved by FERC and included in the 2026/2027 BRA to adopt two of the MMU's recommendations, the inclusion of specific RMR resources as supply in the next two BRAs and the elimination of the categorical exemption to the RPM must offer requirement for all but demand resources.[39] [40]

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. While the market may be long at times, that is not the equilibrium state. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless, a competitive outcome can be assured by appropriate market power mitigation rules within an effective market design. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules.

The basic conclusion of Part A of the MMU's analysis of the 2026/2027 BRA is that data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA and 2026/2027 BRA or the currently expected tight supply conditions and high prices for subsequent capacity auctions. The combined total increase in capacity market revenues resulting from data center load, both actual and forecast, for the 2025/2026 BRA and the 2026/2027 BRA was $16,603,301,829.[41] [42] This total will continue to grow until the issues associated with the additions of large data center loads are addressed. The impact will increase significantly in the 2028/2029 BRA currently scheduled for June 2026, when the maximum and minimum prices defined by the Agreement are no longer effective.

It is misleading to assert that the capacity market results are simply just a reflection of supply and demand. The current conditions are not the result of organic load growth. The current conditions in the capacity market are almost entirely the result of large load additions from data centers, both actual historical and forecast. The growth in data center load and the expected future growth in data center load are unique and unprecedented and uncertain and require a different approach than simply asserting that it is just supply and demand.

It is equally misleading to assert that the PJM Capacity Market does not work as a result of the impact of existing and forecast large data center load additions. Despite all the issues with PJM's changes to the capacity market design, the PJM Capacity Market would have provided for reliability at prices consistent with organic load growth and the cost of new capacity were it not for the paradigm shift represented by the almost inexhaustible demand for power from data centers.

Data center load growth is the core reliability issue facing PJM markets at present. There is still time to address the issue but failure to do so will result in very high costs for other PJM customers and could also result in a switch from competitive markets to cost of service regulation. Customers are already bearing billions of dollars in higher costs as a direct result of existing and forecast data center load as the Market Monitor demonstrated in Part G of the 2025/2026 BRA Analysis report and Part A of the 2027/2027 BRA Analysis Report.[43] [44]

PJM should not continue to interconnect large new data center load if it cannot be served reliably. The goal should be to serve all load that can be served reliably. The MMU recommends that PJM establish a load queue for

39 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).
40 190 FERC ¶ 61,117 (2025).
41 *See*, "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_2025 2026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf> (June 3, 2025).
42 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," ("Part A") <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf> (October 1, 2025).
43 Post Technical Conference Comments of the Independent Market Monitor for PJM (July 7, 2025) *Resource Adequacy Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions*, Docket No. AD25-7.
44 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.

large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile

For the first time since the introduction of the RPM capacity market design, the 2026/2027 BRA used a VRR curve with both a defined maximum price and a defined minimum price. The maximum and minimum prices were based on the Agreement between Governor Shapiro of Pennsylvania and PJM that was incorporated in a PJM filing with FERC.[45] That VRR curve with the defined maximum and minimum price is referred to in this report as the restricted VRR curve. The VRR curve that would have been used absent the Agreement is referred in this report as the unrestricted VRR curve.

The Agreement resulted in a reduction of BRA revenues of $3,169,915,210, or 16.4 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant. If the 2026/2027 BRA had been run with an unrestricted VRR curve, total revenues would have been $19,294,286,100, an increase of $3,169,915,210, or 19.7 percent, compared to the actual auction revenues of $16,124,370,889 (Scenario 1).

The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The maximum price on the VRR curve has a significant impact on market prices particularly when the market is tight. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The VRR curves used in the 2025/2026 BRA included a maximum price equal to gross CONE for most LDAs that resulted in a significant increase in customer payments for load as a result of paying a price above the competitive level. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power.

For the 2026/2027 RPM Base Residual Auction, total reserves were 21,353.2 MW, which is 208.7 MW (UCAP) short of the required reserve level of 21,561.9 MW (UCAP). The level of committed demand resources in the 2026/2027 BRA was 5,530.6 MW, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin. This is not consistent with the defined obligations of DR compared to other capacity resources. DR capacity resources do not have a must offer obligation in the energy market. DR capacity resources do not have a must offer obligation in the capacity market. The definition of performance for DR is not to provide a defined incremental level of MW when called but is only to be at a defined level of demand. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in the 2025/2026 and 2026/2027 Delivery Years will rely on demand response resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets for the first time in the 2025/2026 and 2026/2027 Delivery Years will experience the implications of the definition of demand resources as a purely emergency capacity resource, when demand resources are a significant share of required reserves. Nonetheless, as another significant flaw in the market design, PJM does not include DR in its definition of primary or secondary reserves in the energy market. DR, for all these reasons, is an inferior resource in the capacity market. PJM does not have clear rules defining when the operators must call on DR.

There are currently two important gaps in the market power rules for the PJM Capacity Market related to demand resources. The RPM must offer requirement is not applied to demand resources. There are no market power mitigation rules that apply to demand resources.

For the 2026/2027 BRA, all participants to which the three pivotal supplier (TPS) test was applied (in the RTO RPM market) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing

45 On December 30, 2024, in Docket No. EL25-46-000, Governor Josh Shapiro and the Commonwealth of Pennsylvania filed a complaint against PJM asserting that the maximum price for PJM's capacity auctions is unjust and unreasonable. The Governor and PJM reached an Agreement. On February 20, 2025, in Docket No. ER25-1357-000, pursuant to FPA section 205, PJM submitted proposed revisions to its Tariff to establish a specific maximum price and minimum price for all RPM auctions for the 2026/2027 and 2027/2028 Delivery Years, consistent with the Agreement.

Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[46] [47]

The correct definition of a competitive offer in the capacity market is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with mitigating rational capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the PAI penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and increases CPQR above rational levels, and ultimately raises the price of capacity above the competitive level. Given PJM's recent decision to rely on conservative operations during tight market conditions as evidenced during Polar Vortex 2025 in January 2025, the probability of a PAI is extremely small. In addition, PJM tightened the definition of a PAI and capped the total annual penalty at 1.5 times the resource's capacity market BRA clearing price. As a result, there is no effective performance incentive remaining in the capacity market.

Rather than penalizing capacity resources at extremely high levels for nonperformance only during PAI events, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI events. CP has not worked as the theory suggested. PAI events are high impact, low probability events. The failure of the PAI incentives to prevent a very high level of outages during Winter Storm Elliott illustrates the weakness of incentives based on this type of event. In addition, the actual performance standards were unacceptably weakened in the CP model. The standard of performance in the CP model is (B) * (ELCC accredited UCAP factor for a unit), where B is the balancing ratio and the ELCC accredited UCAP factor is the derating factor. For example, if B were 80 percent, the actual required performance for a unit with an 80 percent ELCC accredited UCAP factor would be only 64 percent of ICAP (.80 * .80). For units with low ELCC accredited UCAP factors, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those

46 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.
47 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

issues.[48] [49] [50] [51] [52] [53] [54] [55] [56] [57] [58] [59] [60] In the first nine months of 2025, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. A majority of capacity investments in PJM were financed by market sources. Of the 57,618.3 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2024/2025 Delivery Years, 43,653.8 MW (76.0 percent) were based on market funding. Of the 5,661.6 MW of additional capacity that cleared in RPM auctions for the 2025/2026 and 2026/2027 Delivery Years, 4,487.6 MW (79.3 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

48 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," (July 6, 2016) <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf>.
49 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," (August 31, 2016) <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf>.
50 See "Analysis of the 2020/2021 RPM Base Residual Auction," (November 11, 2017) <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf>.
51 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," (August 24, 2018) <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf>.
52 See "Analysis of the 2022/2023 RPM Base Residual Auction," (February 22, 2022) <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.
53 See "Analysis of the 2023/2024 RPM Base Residual Auction," (October 28, 2022) <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>.
54 See the "Analysis of the 2024/2025 RPM Base Residual Auction," (October 30, 2023) <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf>.
55 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," (December 14, 2017) <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf>.
56 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," (September 13, 2019) <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf>.
57 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>.
58 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf>.
59 See Monitoring Analytics, L.L.C., Analysis of the 2025/2026 Base Residual Auction, Parts A through H, <https://www.monitoringanalytics.com/reports/Reports/2024.shtml> and< https://www.monitoringanalytics. com/reports/Reports/2025.shtml>.
60 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.

Table 5-2 RPM related MMU reports: January through September, 2025

Date	Name
January 6, 2025	IMM Comments re Capacity Market Rules Docket No. ER25-682 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-682_20250106.pdf
January 10, 2025	IMM Comments re Must Offer Exemption for Capacity Resources Docket No. ER25-785 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-785_20250110.pdf
January 14, 2025	IMM Answer to Motion to Extend re PA BRA Complaint Docket No. EL25-46 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Motion_to_Extend_Docket_No_EL25-46_20250114.pdf
January 23, 2025	IMM Comments re JCA Capacity Complaint Docket No. EL25-18 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_EL25-18_20250123.pdf
January 31,2025	Analysis of the 2025/2026 RPM Base Residual Auction - Part E https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_E_20250131.pdf
February 4, 2025	Analysis of the 2025/2026 RPM Base Residual Auction - Part F https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_F_20250204.pdf
February 7, 2025	PA/PJM Agreement re Maximum and Minimum RPM Prices https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MC_PA_PJM_Agreement_Max_Min_RPM_Prices_20250207.pdf
February 7, 2025	Data Submission Window Opening for the 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2026-2027_RPM_Base_Residual_Auction_20250207.pdf
February 10,2025	IMM Answer to PJM re Capacity Market Rules Docket No. ER25-682 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_PJM_Answer_Docket_No_ER25-682_20250210.pdf
February 18, 2025	IMM Answer re Must Offer Exemption for Capacity Resources Docket No. ER25-785 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answer_Docket_No_ER25-785_20250218.pdf
February 25, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2025/2026 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20250225.pdf
March 6,2025	Data Submission Window Opening for the 2026/2027 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening-20262027_Base_Residual_Auction_Updated_2_20250306.pdf
March 17, 2025	IMM Comments re PJM VRR Docket Nos. ER25-1357 and EL25-46, not consolidated https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_Nos_ER25-1357_and_EL25-46_20250317.pdf
March 19, 2025	IMM Request for Rehearing re Market Seller Offer Caps for Capacity Resources Docket No. ER25-785 https://www.monitoringanalytics.com/filings/2025/IMM_Request_for_Rehearing_Docket_No_ER25-785_20250319.pdf
April 10, 2025	IMM Determinations Posted for the PJM 2026/2027 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2026-2027_Base_Residual_Auction_Revised_20250410.pdf
May 9, 2025	IMM Comments re Mitigating Variability in ELCC Accreditation between RPM Auctions Docket No. ER25-2002 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_ER25-2002_20250509.pdf
May 19, 2025	Quadrennial Review Issues https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Quadrennial_Review_20250519.pdf
May 28, 2025	IMM Answer re Warrior Run Waiver Request Docket No. ER25-2197 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_re_Warrior_Run_Docket_No_ER25-2197_20250528.pdf
May 28, 2025	IMM Answer re Sayreville Waiver Request Docket No. ER25-2162 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_re_Sayreville_Docket_No_ER25-2162_20250528.pdf
May 28, 2025	IMM Answer re Morgantown Waiver Request Docket No. ER25-2190 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_re_Morgantown_Docket_No_ER25-2190_20250228.pdf
June 3, 2025	Analysis of the 2025/2026 RPM Base Residual Auction – Part G Revised https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf
June 9, 2025	IMM Comments re NCEMC Complaint Docket No. EL25-79 https://www.monitoringanalytics.com/filings/2025/IMM_Comments_Docket_No_EL25-79_20250609.pdf
June 9, 2025	IMM Answer to Answer re PJM BRA ELCC Values Docket No. ER25-2002 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answer_Docket_No_ER25-2002_20250609.pdf
June 16, 2025	IMM Answer to PJM Answer re PJM BRA ELCC Values Docket No. ER25-2002 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_PJM_Docket_No_ER25-2002_20250616.pdf
June 30, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2026/2027 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_re_RPM_Must_Offer_Obligations_20250630.pdf
June 30, 2025	Quadrennial Review Proposal and Issues https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Quadrennial_Review_Issues_20250630.pdf
July 7, 2025	Data Submission Window Opening for the 2027/2028 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Data_Submission_Window_Opening_2027-2028_RPM_Base_Residual_Auction_20250707.pdf
July 8, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2026/2027 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_re_RPM_Must_Offer_Obligations_20250708.pdf
July 9, 2025	Quadrennial Review Issues https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Quadrennial_Review_Issues_20250709.pdf
July 7, 2025	Data Submission Window Opening for the 2027/2028 RPM Base Residual Auction (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Data_Submission_Window_Opening_2027-2028_RPM_Base_Residual_Auction_20250707.pdf
July 8, 2025	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2026/2027 Delivery Year (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_re_RPM_Must_Offer_Obligations_20250708.pdf
July 11, 2025	Executive Summary for the IMM ELCC Proposal https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_ELCCSTF_IMM_Executive_Summary_IMM_Proposal_20250711.pdf
July 15, 2025	IMM Answer re EE PIMV Reports Docket No. EL25-87 https://www.monitoringanalytics.com/filings/2025/IMM_Answer_Docket_No_EL25-87_20250715.pdf
July 25, 2025	IMM Response to PJM ELCC Memo (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_ELCCSTF_IMM_Response_20250725.pdf
July 31, 2025	Analysis of the 2025/2026 RPM Base Residual Auction - Part H (PDF) https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_H_20250731.pdf
August 22, 2025	IMM Quadrennial Review Proposal (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Quadrennial_Review_IMM_Gross_and_Net_CONE_20250822.pdf
September 2, 2025	IMM Comments re Large Load Additions CIFP (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_CIFP_Large_Load_Additions_Comments_re_CIFP_scope_20250827.pdf
September 5, 2025	IMM Determinations Posted for the PJM 2027/2028 RPM Base Residual Auction (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2027-2028_Base_Residual_Auction_20250905.pdf
September 8, 2025	IMM Protest re Dairyland Waiver Request Docket No. ER25-3124 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Protest_Waiver_Request_Docket_No_ER25-3124_20250908.pdf
September 10, 2025	IMM Gross and Net CONE Impact of Extended Project Schedule (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MIC_Gross_and_Net_CONE_Impact_of_Extended_Project_Schedule_20250910.pdf
September 24, 2025	IMM Protest re Cordova RPM Must Offer Waiver Request Docket No. ER25-3375 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Protest_Docket_No_ER25-3375_20250924.pdf
September 25, 2025	Quadrennial Review Issues (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_MRC_MC_Quadrennial_Review_Issues_20250925.pdf
September 26, 2025	Data Submission Window Opening for the 2026/2027 RPM Third Incremental Auction (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Data_Submission_Window_Opening_2026-2027_Third_Incremental_Auction_20250926.pdf
October 10, 2025	Analysis of the 2026/2027 RPM Base Residual Auction - Part A (PDF) https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf
October 14, 2025	IMM CIFP Large Load Additions Proposal Memo (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_CIFP_LLA_Proposal_Memo_20251014.pdf
October 14, 2025	IMM CIFP Large Load Additions (LLA) Proposal Presentation (PDF) https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_CIFP_LLA_Proposal_Presentation_20251014.pdf
October 16, 2025	IMM Answer and Motion for Leave to Answer re Dairyland Power Cooperative Waiver Request Docket No. ER25-3124 (PDF) https://www.monitoringanalytics.com/filings/2025/IMM_Answer_Docket_No_ER25-3124_20251016.pdf

Market Design

With the earlier introduction of the Capacity Performance model and the recent introduction of the ELCC model, combined with a tightening of the capacity supply and demand balance in ICAP terms, it is clear that PJM's choices about the details of market design have a potentially dominant impact on capacity market outcomes in PJM. The ongoing decision to allow the addition of a significant number of large new data center loads that cannot be served reliably due to inadequate capacity is the most recent and most significant example.

RPM prices are locational by LDA and may vary depending on transmission constraints into LDAs and local supply and demand conditions.[61] The capacity market is not fully locational. The capacity market locational differences exist only between and among LDAs. The capacity market design assumes that there are no transmission or operational constraints within LDAs and treats all capacity resources within an LDA as perfect substitutes even when they are not. The lack of a fully locational design is a market design flaw that has resulted in the designation of units as RMRs based on internal constraints that were not recognized in the market clearing process. Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for categorically exempt demand resources, and except for resources in a fixed resource requirement (FRR) plan. All load is required to pay for capacity. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. There are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Demand resources may be offered directly into RPM auctions but do not have a requirement to be identifiable physical resources, do not have a must offer obligation, and do not have market seller offer caps and receive the clearing price.

The results of the 2026/2027 RPM Base Residual Auction were significantly affected by flawed market design elements including the lack of a queue for the addition of large new data center loads, by the performance assessment interval (PAI) penalties that are part of the CP design, by PJM's ELCC approach, by the definition of market seller offer caps, by the failure to extend the RPM must offer requirement to demand resources, and by the product definition and lack of market power mitigation for demand resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. PJM filed changes that were approved by FERC and included in the 2026/2027 BRA to adopt two of the MMU's recommendations, the inclusion of specific RMR resources as supply in the next two BRAs and the elimination of the categorical exemption to the RPM must offer requirement for all but demand resources.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the unsupported assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. The use of capacity market penalties rather than energy market incentives created a new risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

61 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

The CP PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives that are not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Winter Storm Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement. In addition, the imposition of PAI penalties on intermittent resources when those resources cannot perform is illogical.

The MMU recommends that PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. In the short run capacity accreditation should eliminate the performance during PV1 and WSE and should recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on the fixed cost of new generating capacity, or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin, and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin. The use of Net CONE was based on the logic of the capacity market, to ensure that the cost of entry was covered between the energy and capacity markets. Net CONE was the missing money that needed to be recoverable in the capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic. Gross CONE was introduced as the maximum price based on concerns that Net CONE would be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE and Gross CONE was used. For the first time since the introduction of the RPM capacity market design, the 2026/2027 BRA used a VRR curve with both a defined maximum price and a defined minimum price.[62] However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are reasonably well defined, much more focus on getting the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

PJM ended the long standing categorical exemption of intermittent resources, capacity storage resources, and hybrid resources from the RPM must offer requirement. Consistent with the MMU's recommendations, that exemption

62 On April 21, 2025, FERC issued an order accepting PJM's proposal to establish a temporary capacity market price cap and floor for the 2026/2027 and 2027/2028 Delivery Years. 191 FERC ¶ 61,066 (April 21, 2025).

was eliminated for all but demand resources. There is no reason to continue to exempt demand resources from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure competitive entry, to ensure open access to the transmission system, and to prevent the exercise of market power via withholding of capacity supply.

For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The MMU recommends that resources return CIRs to the market on the day of retirement.[63]

Consistent with the must offer obligation, performance penalties should not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. That would be the result under the incentive approach recommended by the MMU. If PAI is retained, this would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory.

Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power in the capacity market. When demand resources are pivotal, as they were for the 2026/2027 BRA, they have structural market power and can and do exercise market power. That conclusion does not depend on whether withholding directly benefits those resources through a portfolio effect. The result of the failure to offer can be a significant increase in the market price of capacity above the competitive level when that supply is pivotal. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps in the capacity market, like all other capacity resources.

PJM filed tariff changes that transfer risk caused by the volatile ELCC ratings from generation owners to the load. ELCC ratings may increase or decrease significantly between the time a generator clears in the RPM Base Residual Auction and the final ELCC rating just prior to the start of the delivery year. Under the new tariff rules, generators will be excused from paying the Capacity Resource Deficiency Charge for a deficiency caused by a decrease in the final ELCC rating. Under the prior rules, a Capacity Market Seller was required to cover its short position by acquiring additional capacity or pay a deficiency penalty equal to 20 percent of the base residual auction clearing price for each MW of shortage. The tariff change was filed by PJM on April 18, 2025, and approved by FERC on June 17, 2025.[64] [65] The MMU opposed the change because the new rule does not mitigate the risk as asserted by PJM but simply transfers the ELCC rating volatility risk to the load.[66] The change is inconsistent with basic market logic under which investors bear the risk associated with the ownership of generation.

63 See Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2162-000 (May 28, 2025); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2190-000 (May 28, 2025); and Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2197-000 (May 28, 2025).

64 *Proposal to Mitigate Impacts From Updates to ELCC Accreditation between the Base Residual Auction and the Final ELCC Accreditation Values*, PJM Interconnection L.L.C., Docket ER25-2002 (April 18, 2025).

65 191 FERC ¶ 61,203 (June 17, 2025).

66 See *Comments of the Independent Market Monitor for PJM* (May 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 16, 2025), Docket ER25-2002-000).

Installed Capacity

On January 1, 2025, RPM installed capacity was 179,656.2 MW (Table 5-3).[67] Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 181,728.5 MW on September 30, 2025, an increase of 2,072.3 MW or 1.2 percent from the January 1 level.[68] [69] The 2,072.3 MW increase was the net result of new or reactivated generation (2,020.0 MW), net capacity modifications (2,293.5 MW), decreases in exports (520.8 MW), and increases in imports (12.9 MW), offset by derates (1,906.0 MW), and deactivations or changes in capacity resource status (868.9 MW).

At the beginning of the new delivery year on June 1, 2025, RPM installed capacity was 181,221.6 MW, an increase of 4,056.0 MW or 2.3 percent from the May 31, 2025, level of 177,165.6 MW. This change occurred as a result of deactivations, derates, capacity modifications, and import/export contracts beginning and/or ending at the start of the new delivery year.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2025[70] [71]

	01-Jan-25		31-May-25		01-Jun-25		30-Sep-25	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	21.5	0.0%	21.5	0.0%	24.0	0.0%	24.0	0.0%
Coal	37,793.7	21.0%	37,364.6	21.1%	37,544.6	20.7%	37,544.6	20.7%
Gas	88,760.5	49.4%	88,762.7	50.1%	88,828.3	49.0%	88,826.0	48.9%
Hybird	9.3	0.0%	9.3	0.0%	10.2	0.0%	10.2	0.0%
Hydroelectric	7,674.7	4.3%	7,673.1	4.3%	8,183.4	4.5%	8,183.4	4.5%
Nuclear	32,179.9	17.9%	32,147.1	18.1%	32,149.3	17.7%	32,176.2	17.7%
Oil	3,965.9	2.2%	3,689.0	2.1%	3,762.9	2.1%	4,015.4	2.2%
Solar	5,046.5	2.8%	5,171.8	2.9%	7,843.8	4.3%	8,073.6	4.4%
Solid waste	609.4	0.3%	609.4	0.3%	609.4	0.3%	609.4	0.3%
Wind	3,594.8	2.0%	1,717.1	1.0%	2,265.7	1.3%	2,265.7	1.2%
Total	179,656.2	100.0%	177,165.6	100.0%	181,221.6	100.0%	181,728.5	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2025, as well as the expected installed capacity for the 2026/2027 Delivery Year. On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 20.71 percent on June 1, 2025, and is projected to decrease to 17.5 percent on June 1, 2026. The share of gas increased from 29.1 percent on June 1, 2007, reached a maximum of 50.2 percent in 2024, decreased to 49.0 percent on June 1, 2025, and is projected to increase to 49.9 on June 1, 2026.

67 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
68 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.
69 Wind resources accounted for 2,265.7 MW, and solar resources accounted for 8,073.6 MW of installed capacity in PJM on September 30, 2025. Prior to the 2023/2024 Delivery Year, PJM administratively reduced the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data became available, unforced capability of wind and solar resources was to be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21B: PJM Rules and Procedures for Determination of Generating Capability," § 4 Calculations of ELCC Class Rating, ELCC Resource Performance Adjustment, Accredited UCAP, and Accredited UCAP Factor, Rev. 02 (July 23, 2025). The derating approach has been replaced with ELCC starting in the 2023/2024 Delivery Year.
70 The data for hybrid solar/battery resources are included in the solar data for confidentiality reasons.
71 Installed capacity is based on imports, exports, and PJM's capacity modification ("capmod") database that tracks new and reactivated generation, unit uprates and derates, and deactivations/changes to capacity resource status. Demand Resources are not tracked in this way and are not included here. For analysis of Demand Resources in the capacity market, see the Demand Resources discussion later in this section.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2026

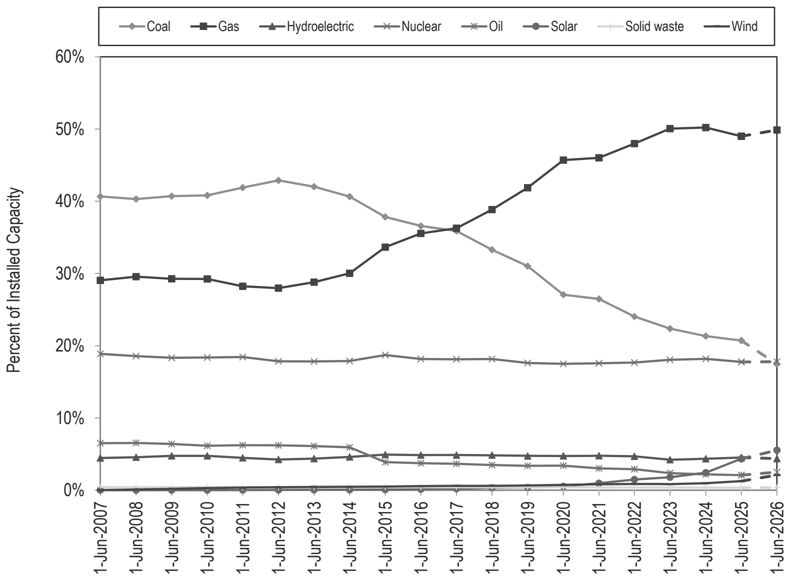


Table 5-4 shows the RPM installed capacity on January 1, 2025, through September 30, 2025, for the top five generation capacity resource owners, excluding FRR committed MW. Dominion Resources, Inc. was an FRR entity for the 2022/2023 through 2024/2025 Delivery Years and shifted their participation from FRR to RPM with the 2025/2026 Delivery Year.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and September 30, 2025

	01-Jan-25			31-May-25			01-Jun-25			30-Sep-25		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Constellation Energy Generation, LLC	20,193.6	13.9%	1	20,132.8	14.1%	1	20,191.3	12.0%	2	20,191.3	12.0%	2
LS Power Equity Partners, L.P.	12,691.6	8.7%	2	12,882.0	9.0%	2	11,689.7	7.0%	4	10,594.9	6.3%	4
Vistra Energy Corp.	11,748.5	8.1%	3	11,758.4	8.2%	3	12,234.5	7.3%	3	12,234.5	7.3%	3
ArcLight Capital Partners, LLC	11,406.1	7.9%	4	11,385.6	8.0%	4	11,510.0	6.9%	5	6,658.4	4.0%	7
Talen Energy Corporation	10,169.2	7.0%	5	10,142.0	7.1%	5	10,004.0	6.0%	6	9,885.9	5.9%	5
Dominion Resources, Inc.	299.8	0.2%	47	419.0	0.3%	43	22,063.2	13.1%	1	21,925.2	13.0%	1

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2025, to September 30, 2025, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and September 30, 2025

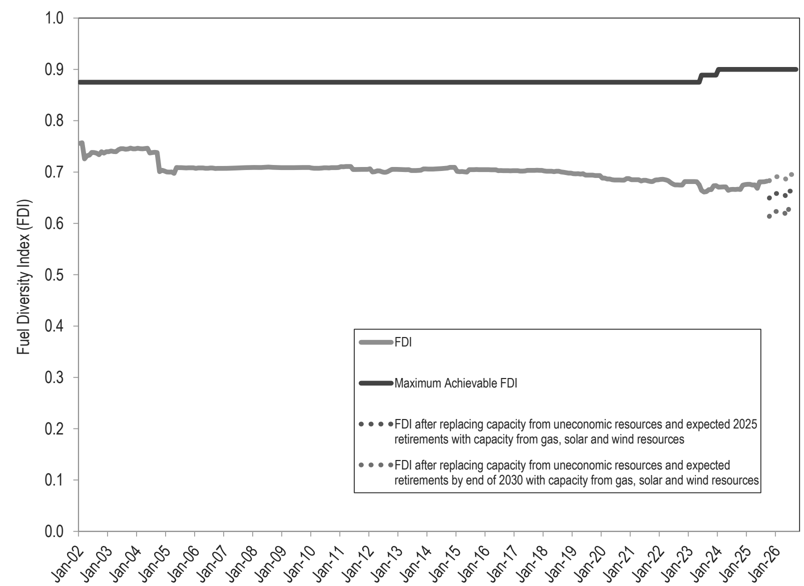
	01-Jan-25		31-May-25		01-Jun-25		30-Sep-25	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	131,485.2	73.2%	128,508.7	72.5%	131,492.5	72.6%	131,893.0	72.6%
Nonmarket	48,171.0	26.8%	48,656.9	27.5%	49,729.1	27.4%	49,835.5	27.4%
Total	179,656.2	100.0%	177,165.6	100.0%	181,221.6	100.0%	181,728.5	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[72] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are in Table 5-3. FDI_c calculations prior to June 1, 2023 included eight fuel types. Batteries were added to the resource mix on June 1, 2023, and hybrid solar resources were added on January 1, 2024. The maximum achievable index with nine fuel types is 0.889. The maximum achievable index with ten fuel types is 0.900. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[73] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[74] The FDI_c on September 30, 2025 increased 2.4 percent in comparison with the FDI_c on September 30, 2024. Figure 5-2 also includes the expected FDI_c through September 30, 2026. The expected FDI_c is indicated in Figure 5-2 by the dotted orange line.

The FDI_c is used to measure the impact on fuel diversity of potential retirements in 2025 through 2030. A total of 34,733 MW of capacity are at risk of retirement, consisting of 4,684 MW currently planning to retire, 16,786 MW expected to retire for regulatory reasons and 13,264 MW expected to be uneconomic.[75] The dotted green line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected 2025 retirements were replaced by gas, wind and solar capacity.[76] The counterfactual FDI_c on September 30, 2026 under these assumptions is 4.6 percent lower than the expected FDI_c on September 30, 2026. The dotted blue line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected retirements through 2030 was replaced by gas, wind and solar capacity.[77] The counterfactual FDI_c on September 30, 2026 in this scenario is 9.7 percent lower.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through September 30, 2026



72 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity. The FDI_c includes derated capacity values for intermittent capacity subject to derating.

73 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 Annual State of the Market Report for PJM* for additional details.

74 See the *2019 Annual State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.

75 See the *2024 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

76 It is assumed that 519.1 MW of replacement capacity is from solar units and 439.2 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 8,962.7 GWh of generation in the first nine months of 2026 assuming the applicable PJM ELCC capacity derate factors and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-37. This level of GWh represents the increase in renewable generation required by RPS in the first nine months of 2026 over the level of renewable generation that was required by RPS in the first nine months of 2025. The split between solar and wind is based on queue data.

77 It is assumed that 1,658.4 MW of replacement capacity is from solar units and 1,960.1 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 33,840.5 GWh of generation in the first nine months of 2030 assuming the applicable PJM ELCC capacity derate factors and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-37. This level of GWh represents the increase in renewable generation required by RPS in the first nine months of 2030 over the level of renewable generation that was required by RPS in the first nine months of 2025. The split between solar and wind is based on queue data.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a three year forward looking, annual, locational market, with a must offer requirement for existing generation capacity resources, except for demand response resources, and except for resources owned by entities that elect the fixed resource requirement (FRR) option, and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.

The standard schedule is that annual base residual auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[78] In the first nine months of 2025, the 2026/2027 RPM Base Residual Auction and 2026/2027 RPM Base Residual Auction were conducted. The auction schedule has diverged significantly from the standard schedule in recent years.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2024/2025 Delivery Year. The 13,506.2 MW increase was the result of new generation capacity resources (46,491.1 MW), reactivated generation capacity resources (1,380.4 MW), uprates (9,746.8 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (538.9 MW), offset by a net decrease in capacity imports (1,513.1 MW), deactivations (58,847.3 MW) and derates (6,258.1 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of, or short of, the target installed reserve margin (IRM) for June 1, 2022, through June 1, 2026, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Prior to the 2025/2026 Delivery Year, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. Effective with the 2025/2026 Delivery Year, replacement capacity transactions can be completed only after the accredited UCAP factors for the delivery year are finalized, but before the start of the delivery day. Early replacement transactions can be approved for defined physical replacements.

Changes in Generation Capacity[79]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2024/2025 Delivery Year, internal installed capacity decreased by 7,487.1 MW after accounting for new capacity resources, reactivations, and uprates (57,618.3 MW) and capacity deactivations and derates (65,105.4 MW).[80]

For the current year (2025/2026), new generation capacity is defined as capacity that cleared an RPM auction for the first time for the specified delivery year. Based on expected completion rates of cleared new generation capacity (2,752.8 MW) and pending deactivations (760.0 MW), PJM capacity is expected to increase by 1,992.8 MW through the 2025/2026 Delivery Year.

78 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

79 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

80 These results are for internal capacity only and do not include, for example, imports or exports or the impact of integrations of new areas.

Table 5-6 Generation capacity changes: 2007/2008 through 2024/2025[81]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
2021/2022	3,309.3	6.0	412.2	0.0	38.5	1,066.1	2,197.6	125.5	376.8
2022/2023	4,743.2	0.0	417.0	0.0	(469.3)	(868.0)	7,460.5	302.0	(2,203.6)
2023/2024	2,696.8	0.0	420.5	0.0	(47.9)	1,067.8	5,149.2	1,441.1	(4,588.7)
2024/2025	1,724.3	0.0	919.5	0.0	17.1	212.0	1,068.0	737.7	643.2
Total	46,491.1	1,380.4	9,746.8	21,967.5	(1,513.1)	(538.9)	58,847.3	6,258.1	13,506.2

As shown in Table 5-7, total reserves on June 1, 2025, were 19,999.9 MW, which is 205.1 MW (UCAP) short of the required reserve level of 20,205.0 MW (UCAP). In the 2026/2027 BRA, total reserves were 21,353.2 MW, which is 208.7 MW (UCAP) short of the required reserve level of 21,561.9 MW (UCAP). The level of committed demand resources in the 2026/2027 BRA was 5,530.6 MW, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin.

The fact that one quarter (25.6 percent of total reserves) of the PJM reserves depend on demand resources that are not subject to the RPM must offer requirement, a core part of the capacity market design, means that reliability is significantly less certain than the stated reserve margins indicate.

81 The capacity changes in this report are calculated based on June 1 through May 31.

Table 5-7 RPM reserve margin: June 1, 2022, to June 1, 2026[82] [83]

	01-Jun-22	01-Jun-23	01-Jun-24	01-Jun-25	01-Jun-26	
Forecast peak load ICAP (MW)	149,263.6	149,382.2	151,631.1	154,534.1	159,329.1	A
FRR peak load ICAP (MW)	28,292.8	29,554.6	30,431.0	11,720.3	12,633.9	B
PRD ICAP (MW)	230.0	235.0	305.0	224.0	115.0	C
Installed reserve margin (IRM)	14.9%	14.9%	17.7%	17.8%	19.1%	D
Pool wide average EFORd	5.08%	4.87%	5.10%			E
Pool wide accredited UCAP factor				79.63%	76.99%	F
Forecast pool requirement (FPR)	1.091	1.093	1.117	0.938	0.917	G=(1+D)*(1-E) or G=(1+D)*F
RPM committed less deficiency UCAP (MW) (generation and DR)	137,944.8	136,401.8	138,318.6	133,544.1	134,205.3	H
RPM committed less deficiency ICAP (MW) (generation and DR)	145,327.4	143,384.6	145,751.9	167,705.8	174,315.2	J=H/(1-E) or J=H/F
RPM peak load ICAP (MW)	120,740.8	119,592.6	120,895.1	142,589.7	146,580.2	K=A-B-C
Reserve margin ICAP (MW)	24,586.6	23,792.0	24,856.9	25,116.0	27,735.0	L=J-K
Reserve margin (%)	20.4%	19.9%	20.6%	17.6%	18.9%	M=L/K
Reserve margin in excess of IRM ICAP (MW)	6,596.3	5,972.7	3,458.4	(264.9)	(261.8)	N=L-D*K
Reserve margin in excess of IRM (%)	5.5%	5.0%	2.9%	(0.2%)	(0.2%)	P=N/K
RPM peak load UCAP (MW)	114,607.2	113,768.4	114,729.4	113,544.2	112,852.1	Q=K*(1-E) or Q=K*F
RPM reliability requirement UCAP (MW)	131,679.9	130,714.7	135,039.8	133,749.2	134,414.0	R=K*G
Reserve margin UCAP (MW)	23,337.6	22,633.4	23,589.2	19,999.9	21,353.2	S=H-Q
Reserve cleared in excess of IRM UCAP (MW)	6,264.9	5,687.1	3,278.8	(205.1)	(208.7)	T=H-R
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	U
Projected reserve margin	20.4%	19.9%	20.6%	17.6%	18.9%	V=(J-U/(1-E))/K-1 or V=(J-U/F)/K-1

Sources of Funding[84]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2024/2025 Delivery Year totaled 47,871.5 MW (83.1 percent of all additions), with 36,670.1 MW from market funding and 11,201.4 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2024/2025 Delivery Year totaled 9,746.8 MW (16.9 percent of all additions), with 6,983.7 MW from market funding and 2,763.1 MW from nonmarket funding. In summary, of the 57,618.3 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2024/2025 Delivery Years, 43,653.8 MW (76.0 percent) were based on market funding.

Of the 5,661.6 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2025/2026 and 2026/2027 Delivery Years, 357.6 MW are not yet in service, all of which have market funding. Applying the historical completion rates, 65.5 percent of all the projects in development are expected to go into service, 234.4 MW of the 357.6 MW in development market funded projects.[85]

82 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin. Effective with the 2026/2027 Deliver Year, EE resources no longer participate in the PJM Capacity Market. See 189 FERC ¶ 61,095 (November 5, 2024).
83 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.
84 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).
85 See the *2024 Annual State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning.

Of the 5,304.0 MW of the additional generation capacity that cleared in RPM auctions for the 2025/2026 and 2026/2027 Delivery Years and are already in service, 4,130.0 MW (77.9 percent) are based on market funding and 1,174.0 MW (22.1 percent) are based on nonmarket funding.

In summary, 4,487.6 MW (79.3 percent) of the additional generation capacity (357.6 MW not yet in service and 4,130.0 MW in service) that cleared in RPM auctions for the 2025/2026 and 2026/2027 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 1,174.0 MW (22.1 percent) of generation that cleared the RPM auctions for the 2025/2026 and 2026/2027 Delivery Years.

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

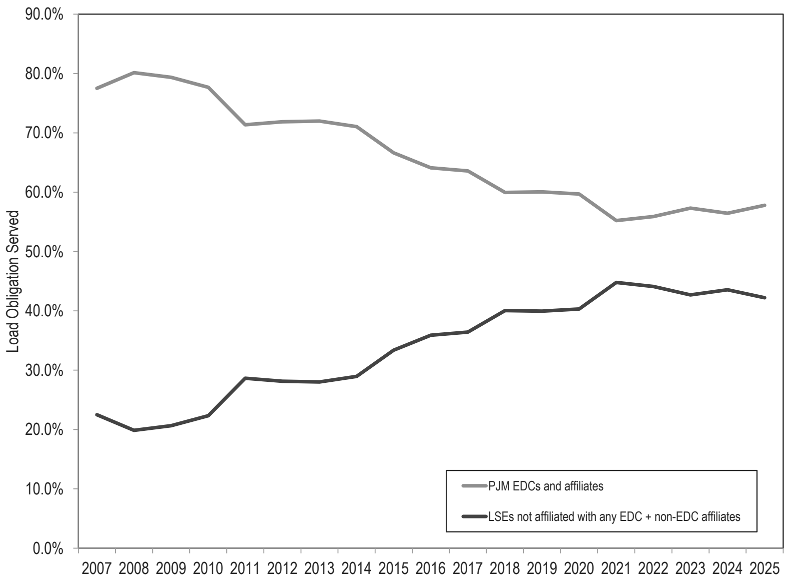
On June 1, 2025, PJM EDCs and their affiliates maintained a majority market share of load obligations under RPM, together totaling 57.8 percent (Table 5-8), up from 56.4 percent on June 1, 2024. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 42.2 percent, down from 43.6 percent on June 1, 2024. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2025, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 57.8 percent on June 1, 2025. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 42.2 percent on June 1, 2025.[86]

86 Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2024 and June 1, 2025

	01-Jun-24		01-Jun-25		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	106,462.1	56.4%	86,471.6	57.8%	(19,990.5)	1.4%
LSEs not affiliated with any EDC + non EDC Affiliates	82,180.1	43.6%	63,166.5	42.2%	(19,013.6)	(1.4%)
Total	188,642.2	100.0%	149,638.1	100.0%	(39,004.1)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2025



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted three months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run three months prior to the delivery year when auctions follow the traditional schedule.[87] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA, cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2025/2026 RPM Third Incremental Auction, BGE had 5,024.2 MW of CTRs with a total value of $360.6 million and DOM had 1,752.6 MW of CTRs with a total value of $112.8 million. BGE had 65.7 MW of customer funded ICTRs with a total value of $4.7 million. BGE had 306.0 MW of ICTRs due to Incremental Rights Eligible Required Transmission Enhancements with a value of $22.0 million.

The 2026/2027 RPM Base Residual Auction cleared at $329.17 with no price separation and therefore the value of CTRs is $0.

Demand Curve

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[88] Figure 5-4 shows the shape of the VRR curve for the 2026/2027 RPM Base Residual Auction.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity, which is the Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

87 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 61 (July 23, 2025).

88 The formula for the MW level where the VRR curve begins the downward slope is given by *(Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)]*.

Effective for the 2018/2019 through 2021/2022 Delivery Years, a revised VRR curve was implemented after PJM conducted a triennial review.[89] [90] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve was increased to be the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99.8 percent of the reliability requirement. The first downward sloping segment was from 99.8 percent and 102.5 percent of the reliability requirement. The second downward sloping segment was from 102.5 percent and 107.6 percent of the reliability requirement.

Effective for the 2022/2023 through 2025/2026 Delivery Years, a revised VRR curve was implemented after PJM conducted a quadrennial review.[91] The maximum price on the VRR curve was the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 98.9 percent of the reliability requirement. The first downward sloping segment was from 98.9 percent and 101.6 percent of the reliability requirement. The second downward sloping segment was from 101.6 percent and 106.8 percent of the reliability requirement (Figure 5-4).

Effective for the 2026/2027 through 2029/2030 Delivery Years, a revised VRR curve was implemented after PJM conducted a quadrennial review.[92] The maximum price on the VRR curve is the greater of Gross CONE or 1.75 times Net CONE for all unforced capacity MW between 0 and 99.0 percent of the reliability requirement. The first downward sloping segment is from 99.0 percent and 101.5 percent of the reliability requirement. The second downward sloping segment is from 101.5 percent and 104.5 percent of the reliability requirement.

The VRR curve was then changed significantly based on PJM's filing to establish the maximum price point on the VRR curve equal to "approximately" $325/MW-day in UCAP with a new MW point that is inconsistent with the tariff definition, a new minimum price point on the VRR curve of "approximately" $175/MW-day in UCAP for an unlimited number of MW that is inconsistent with the tariff, and a VRR curve shape not consistent with the tariff definition, for all Reliability Pricing Model ("RPM") Auctions, including Base Residual Auctions and Incremental Auctions, for the 2026/2027 and 2027/2028 Delivery Years.[93] The VRR curve has always had a maximum price. The VRR curve has always had a minimum price equal to zero. The proposal would set the maximum price level at somewhat higher than 1.5 times Net CONE. The Market Monitor's position is that the maximum price should be equal to the lesser of 1.5 times Net CONE or Gross CONE.[94] The MMU opposed the imposition of a completely unsupported floor price that is inconsistent with the longstanding VRR curve design.

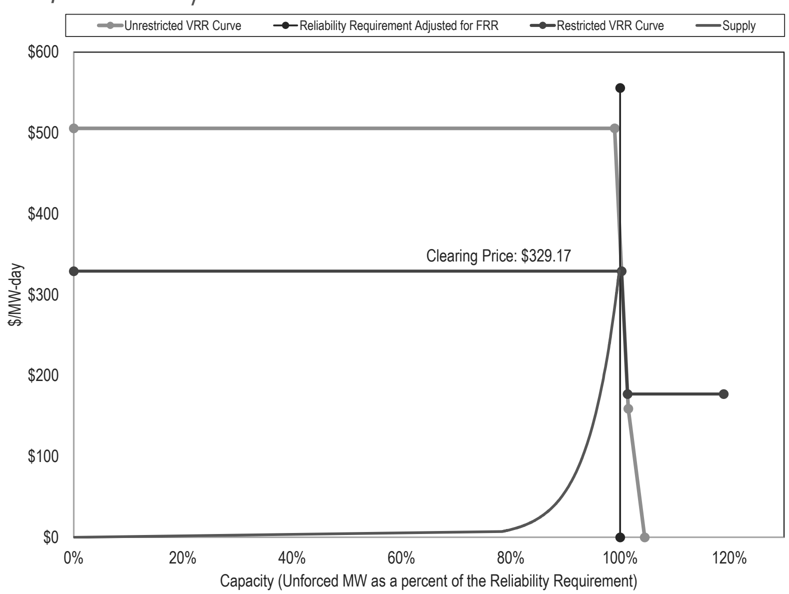
The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE). The use of Net CONE was based on the logic of the capacity market, to ensure that between the energy and capacity markets the cost of entry was covered. Net CONE was the missing money that needed to be recoverable in the capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic as is the use of 1.75 times Net CONE which is frequently greater than Gross CONE. Gross CONE was introduced as the maximum price based on concerns that Net CONE would be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE, and Gross CONE was actually used. However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices based on a judgment about what prices should be despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are reasonably well defined, much more focus on getting

89 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.
90 153 FERC ¶ 61,035 (October 15, 2015).
91 167 FERC ¶ 61,029 (April 15, 2019).
92 182 FERC ¶ 61,073 (Feb. 14, 2023).
93 PJM Filing. Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. ER25-1357 (Feb. 20, 2025).
94 See Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, (April 16, 2025). <https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answer_Docket_No_ER25-1357_20250416.pdf>.

the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2026/2027 RPM BRA.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2026/2027 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2025/2026 RPM Third Incremental Auction and the 2026/2027 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[95] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[96] [97] [98]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

95 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
96 See OATT Attachment DD § 6.5.
97 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
98 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

Table 5-9 RSI results: 2022/2023 through 2026/2027 RPM Auctions[99]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2022/2023 Third Incremental Auction				
RTO	0.68	0.50	43	43
MAAC	0.40	0.05	9	9
2023/2024 Base Residual Auction				
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2023/2024 Third Incremental Auction				
RTO	0.77	0.76	51	15
MAAC	0.41	0.76	17	9
EMAAC	0.45	0.18	10	10
BGE	0.00	0.00	1	1
2024/2025 Base Residual Auction				
RTO	0.77	0.64	133	133
MAAC	0.59	0.11	9	9
EMAAC	0.48	0.00	2	2
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2024/2025 Third Incremental Auction				
RTO	0.88	0.59	64	64
MAAC	0.60	0.17	10	10
EMAAC	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2025/2026 Base Residual Auction				
RTO	0.82	0.62	128	128
BGE	0.00	0.00	0	0
Dominion	0.00	0.00	0	0
2025/2026 Third Incremental Auction				
RTO	0.60	0.31	75	75
BGE	0.00	0.00	0	0
2026/2027 Base Residual Auction				
RTO	0.82	0.64	153	153

99 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[100] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[101] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement were established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, were established for each modeled LDA.[102] [103] Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, were established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational

100 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
101 OATT Attachment DD § 5.10 (a) (ii).
102 146 FERC ¶ 61,052 (2014).
103 Locational Deliverability Areas are shown in maps in the *2021 Annual State of the Market Report for PJM*, Volume 2, Section 5, "Capacity Market" at "Locational Deliverability Areas (LDAs)".

UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[104]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The calculation of CETL should only include capacity imports into PJM where the capacity has an explicit must offer requirement in the PJM Capacity Market. These could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM capacity market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to deriver CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[105]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[106] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[107] [108] [109] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point

104 OATT Attachment DD § 5.6.6(b).

105 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (Dec. 21, 2017).

106 161 FERC ¶ 61,197 (2017).

107 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.

108 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 61 (July 23, 2025).

109 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 61 (July 23, 2025).

to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[110]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[111] [112] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM region; and is in full commercial operation prior to the first day of the delivery year.[113] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[114]

110 OATT Schedule 1 § 1.10.1A.
111 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
112 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 61 (July 23, 2025).
113 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
114 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

As shown in Table 5-10, of the 1,281.7 MW of imports offered in the 2026/2027 RPM Base Residual Auction, 1,281.7 MW cleared. Of the cleared imports, 697.4 MW (54.4 percent) were from MISO.

Table 5-10 RPM imports: 2007/2008 through 2026/2027 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6
2024/2025	949.9	820.4	577.2	577.2	1,527.1	1,397.6
2025/2026	700.5	700.5	568.0	568.0	1,268.5	1,268.5
2026/2027	697.4	697.4	584.3	584.3	1,281.7	1,281.7

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[115] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This

115 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

Effective with the 2020/2021 Delivery Year, DR includes annual and summer products. Annual Demand Resources are required to be available on any day during the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.

Summer-Period Demand Resources are required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. to 10:00 p.m. EPT.

As shown in Table 5-11, and Table 5-12, committed DR was 5,782.9 MW for June 1, 2025, as a result of cleared capacity for demand resources in RPM auctions for the 2025/2026 Delivery Year (6,265.9 MW) less replacement capacity (483.0 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2022 to June 1, 2026[116] [117] [118] [119]

		UCAP (MW)																
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK	Dominion	JCPL
01-Jun-22	DR cleared	8,866.2	2,821.3	1,139.9	489.2	48.4	294.6	93.8	325.3	949.4	191.8	1,521.9	163.9	661.7	210.5	185.1		
	EE cleared	5,734.8	2,303.6	1,265.3	499.4	53.5	431.0	201.6	287.5	485.0	55.9	792.6	211.9	312.4	129.4	186.8		
	DR net replacements	(570.0)	(395.4)	(138.0)	(12.6)	1.7	(49.4)	(12.6)	(21.5)	(99.6)	(28.2)	127.5	8.9	(165.2)	(24.1)	24.3		
	EE net replacements	(4.0)	11.8	7.0	14.9	0.0	(2.1)	15.4	8.7	(22.2)	(0.5)	0.0	6.2	(9.8)	(13.0)	0.0		
	RPM load management	14,027.0	4,741.3	2,274.2	990.9	103.6	674.1	298.2	600.0	1,312.6	219.0	2,442.0	390.9	799.1	302.8	396.2		
01-Jun-23	DR cleared	8,174.1	2,411.4	975.9	343.6	52.2	272.7	126.1	175.2	916.2	189.4	1,253.2	168.4	583.4	209.3	175.4		
	EE cleared	5,896.4	2,438.6	1,341.4	569.5	59.3	443.4	210.4	298.6	451.8	46.3	961.2	270.9	306.1	102.4	164.3		
	DR net replacements	(466.2)	(229.5)	(3.8)	(4.9)	22.8	3.4	2.6	(25.0)	47.2	(63.4)	160.7	20.1	(123.3)	(24.0)	25.0		
	EE net replacements	(5.3)	(2.2)	(1.0)	7.6	9.0	11.6	13.7	7.6	(15.3)	(0.5)	(20.9)	0.0	(6.2)	(7.9)	0.7		
	RPM load management	13,599.0	4,618.3	2,312.5	915.8	143.3	731.1	352.8	456.4	1,399.9	171.8	2,354.2	459.4	760.0	279.8	365.4		
01-Jun-24	DR cleared	8,064.7	2,497.6	1,004.0	358.5	46.0	285.7	98.2	160.4	682.6	141.6	1,554.0	198.1	603.4	192.9	221.9		
	EE cleared	7,716.0	3,543.5	2,064.9	787.4	99.9	802.9	392.0	398.9	587.6	54.9	1,063.4	388.5	391.4	128.3	188.1		
	DR net replacements	(364.8)	(197.4)	9.1	43.0	35.2	(7.3)	(14.9)	19.3	50.9	(58.3)	(56.0)	23.7	(138.9)	(6.2)	(5.4)		
	EE net replacements	(48.0)	(43.6)	(15.4)	21.3	14.1	(6.5)	(0.1)	9.1	(30.6)	0.0	1.2	12.2	(38.4)	(5.6)	(3.7)		
	RPM load management	15,367.9	5,800.1	3,062.6	1,210.2	195.2	1,074.8	475.2	587.7	1,290.5	138.2	2,562.6	622.5	817.5	309.4	400.9		
01-Jun-25	DR cleared	6,265.9	1,860.8	784.9	304.0	65.0	228.9	65.8	135.7	712.7	97.3	1,090.5	168.3	424.9	141.0	159.6	673.5	
	EE cleared	1,493.2	674.7	433.5	154.7	24.0	184.0	100.0	80.0	69.1	6.6	337.6	74.7	45.7	18.5	24.9	154.2	
	DR net replacements	(483.0)	(140.4)	(60.2)	(11.6)	(30.3)	(10.4)	(14.3)	(15.1)	(39.8)	(4.8)	(29.0)	3.5	(10.2)	(0.2)	(39.9)	(151.0)	
	EE net replacements	(11.6)	32.8	25.7	(2.6)	(1.3)	7.5	3.3	(2.6)	(6.8)	(0.1)	1.0	0.0	10.0	(0.2)	(1.6)	(11.6)	
	RPM load management	7,264.5	2,427.9	1,183.9	444.5	57.4	410.0	154.8	198.0	735.2	99.0	1,400.1	246.5	470.4	159.1	143.0	665.1	
01-Jun-26	DR cleared	5,530.6	1,553.8	614.1	339.7	33.9	179.1	45.6	189.8	510.0	75.7	969.6	149.9	319.8	149.8	114.9	555.1	59.2
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	5,530.6	1,553.8	614.1	339.7	33.9	179.1	45.6	189.8	510.0	75.7	969.6	149.9	319.8	149.8	114.9	555.1	59.2

116 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
117 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
118 EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 Delivery Year, and EE resources are not defined to be capacity resources in any way as a result. EE resources do not clear in the capacity auctions.
119 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2026[120] [121] [122]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,518.5	1.091	9,290.2
01-Jun-23	8,174.1	0.0	(466.2)	7,707.9	(161.5)	7,546.4	7,383.0	1.093	8,069.6
01-Jun-24	8,064.7	0.0	(364.8)	7,699.9	(507.4)	7,192.5	6,758.7	1.117	7,549.5
01-Jun-25	6,265.9	0.0	(483.0)	5,782.9	(209.4)	5,573.5	7,748.7	0.770	5,966.5
01-Jun-26	5,530.6	0.0	0.0	5,530.6	0.0	5,530.6	0.0	0.690	0.0

ELCC: The Capacity Value of Resources

Given that many PJM states have aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices at times of high intermittent output. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value of renewables is calculated correctly.

120 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

121 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

122 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

The units of measurement for the PJM capacity market auctions are unforced capacity (UCAP). PJM uses conversion factors to convert installed capacity MW (ICAP) into UCAP MW and this process is known as capacity accreditation. Prior to the 2023/2024 Delivery Year, EFORd values for thermal generators were used to convert ICAP to UCAP. Conversion factors for wind and solar generators were based on energy output during summer peak hours. Conversion factors for storage resources were equal to the maximum capability during 10 continuous hours of operation. The conversion factor for Demand Resources was equal to the forecast pool requirement (FPR). On July 30, 2021, FERC approved new PJM rules for defining/derating the capacity value of intermittent and storage resources, based on PJM's interpretation of the effective load carrying capability (ELCC) method.[123] PJM's average ELCC accreditations for intermittent and storage resources relied on the average capability by resource class for the 2023/2024 and 2024/2025 Delivery Years. Revisions, filed in October 2023, changed the capacity accreditation calculation to a marginal ELCC approach, applicable to all resource types. Beginning with the 2025/2026 Delivery Year, capacity accreditations are based on the revised marginal ELCC approach. The PJM marginal ELCC approach was accepted by FERC in January 2024.[124]

PJM's approach to ELCC is based on the correct high level insight that there is a need to calculate the availability of different resource types, but the actual implementation does not do that correctly and results in a set of illogical outcomes. For example, PJM assigned penalties to solar resources during Winter Storm Elliott in December 2022 when solar resources did not generate power after dark. PJM's ELCC calculations rely on a significant overweighting

123 See 176 FERC ¶ 61,056.

124 186 FERC ¶61,080 (January 30, 2024).

of generator performance during the Polar Vortex in 2014 and Winter Storm Elliott in 2022 that results in artificially suppressed ELCC values for thermal resources and other resource types.

Under the PJM ELCC approach a solar resource is assigned a derating factor, and the derated MW are asserted to be equivalent to a perfect resource accredited at that MW level. PJM assigned penalties to solar resources during Elliott when they did not generate power after dark. This is clearly not correct and illustrates one of the flaws in the ELCC logic. The solar resource is available for sunny hours and not for unsunny hours. A solar resource is not expected to generate at night and should not face penalties for failing to do what it obviously cannot. ELCC does not convert intermittent resources, or any resource, into a perfect resource, or even the equivalent of a perfect resource. This illogical implication of PJM's ELCC means that there is a significant flaw in the ELCC approach. The penalties were assessed because the ELCC method determined that 1 MW of solar nameplate capacity was equivalent to 0.54 MW of perfect capacity, meaning capacity that is always available at the derated level, even in the middle of the night.[125]

The MMU opposes PJM's ELCC rules because they are an administrative determination by PJM based on a black box model of the capacity value of resources, they rely on significant counterfactual behavioral assumptions for storage and demand response resources, are not unit specific, are not hourly, are not locational, introduce significant volatility to the capacity accreditations, do not recognize the winter capability of thermal resources, overweight unit performance during Winter Storm Elliott, do not recognize actual performance in the delivery year and are an ex ante approach that must assume a capacity resource fleet for determining the ELCC marginal class ratings.[126] PJM does not check the actual cleared capacity in capacity market auctions to verify if the cleared capacity is expected to provide the target reliability.

125 "ELCC Class Ratings for 2024-2025 BRA," PJM Interconnection L.L.C. (December 28, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.
126 See Protest of the Independent Market Monitor for PJM, Docket ER24-99-000, et al. (November 9, 2023); Comments on Response to Deficiency Notice, Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (December 21, 2023); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (January 12, 2024); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (January 24, 2024).

The ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market. ELCC was developed as, and remains, a utility planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability. The impetus made sense but the actual application of the ELCC planning tool cannot work in markets that include intermittent or thermal resources. The underlying logic makes sense but PJM's implementation does not.

As a result of all these issues, the MMU has concluded that ELCC is not a viable method for determining the reliability contributions of capacity resources. The MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[127] [128] [129]

The ELCC ratings produced by the marginal approach in general, and by PJM's specific marginal approach specifically, are inherently volatile. PJM has calculated the marginal ELCC class ratings for the 2025/2026 Delivery Year on five separate occasions. Table 5-13 shows the results of each calculation. Each calculation is dependent upon the load forecast model, the combination of actual historical performance and changes in experienced weather, and the assumed forward looking resource mix. The PJM 2024 load forecast model was used to produce the February 2024, March 2024 and January 2025 ELCC ratings. The ELCC ratings posted on December 31, 2024, used an interim 2025 load forecast model. In early January, PJM removed the posted ELCC ratings from December 31, 2024, and posted recalculated ratings using the 2024 load forecast model. The modified ELCC ratings were posted on January 23, 2025. The January 23, 2025, ratings are the final ELCC ratings for 2025/2026 Delivery Year.[130] The ELCC rating changes have significant impacts on the

127 For additional details on the MMU proposal see "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)", Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.
128 Any generation from a resource in excess of its CIR value is equivalent to generation from an energy only resource and should not be included in the calculation of the capacity value of the resource or in the calculation of the derated ELCC class ratings that define the capacity value of the resource. Updated rules beginning with the 2025/2026 Delivery Year require that ELCC accreditations exclude energy in excess of a generator's CIR. See 183 FERC ¶ 61,009 (April 7, 2023).
129 New rules beginning with the 2025/2026 Delivery Year correctly limit the delivered energy to the CIR level in the ELCC calculations. The new rules also include a complex transition process that allocates available headroom to intermittent resources with understated CIRs. The new rules apply to Delivery Year 2025/2026 BRA and subsequent delivery years. *See* 183 FERC ¶ 61,009 (April 7, 2023).
130 See Item 5 in Markets and Reliability Committee Meeting Materials, *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 2025/2026 3IA* at 2, PJM Interconnection L.L.C. (January 23, 2025) <https://www.pjm.com/committees-and-groups/committees/mrc>.

amount of cleared capacity. Table 5-14 shows the difference between capacity that cleared the 2025/2026 Base Residual Auction and the updated capacity MW value based on the final ELCC ratings for 2025/2026 posted on January 23, 2025. In total, the capacity values decreased by 928.5 MW (UCAP) or 0.7 percent. Capacity market sellers are obligated to obtain additional capacity prior to the delivery year if they are short as a result of a reduction in ELCC rating between the BRA and the final ELCC rating from PJM's ELCC rating changes. Had PJM used the ELCC ratings posted on December 31, 2024, the capacity values would have decreased by 3,793.3 MW or 2.8 percent.

Table 5-13 Marginal ELCC ratings for the 2025/2026 Delivery Year

	2025/2026 Delivery Year				
ELCC Class	December 2023	February 2024	March 2024	December 2024	January 2025
Onshore Wind	21%	35%	35%	42%	38%
Offshore Wind	39%	60%	60%	71%	62%
Solar Fixed	15%	9%	9%	8%	10%
Solar Tracking	25%	14%	14%	11%	14%
Landfill Intermittent	56%	55%	54%	51%	51%
Hydro Intermittent	41%	36%	37%	37%	37%
4-hr Storage	76%	59%	59%	44%	55%
6-hr Storage	85%	67%	67%	53%	65%
8-hr Storage	89%	69%	68%	58%	68%
10-hr Storage	92%	78%	78%	67%	77%
Demand Response	95%	77%	76%	68%	77%
Nuclear	96%	96%	95%	95%	95%
Coal	86%	85%	84%	83%	83%
Gas Combined Cycle	87%	80%	79%	77%	78%
Gas Combustion Turbine	74%	62%	62%	59%	63%
Gas Combustion Turbine Dual Fuel	90%	78%	79%	78%	79%
Diesel Utility	91%	90%	92%	92%	92%
Steam	78%	70%	75%	73%	74%

Table 5-14 Impact of ratings changes on cleared capacity[131]

	MW (UCAP)	Reduction in capacity value compared to Base Residual Auction	Percent change in capacity value compared to Base Residual Auction
2025/2026 Base Residual Auction Cleared Capacity	135,684.0		
Updated Cleared Capacity based on Jan 23, 2025 ELCC Ratings	134,755.5	(928.5)	(0.7%)
Updated Cleared Capacity based on Dec 31, 2024 ELCC Ratings	131,890.7	(3,793.3)	(2.8%)

131 PJM stated that the 2024 load forecast model was used because it is the "most recently finalized PJM load forecast." The January 23, 2025, ELCC Ratings are based on the PJM 2024 load forecast model. The December 31, 2024, ELCC Ratings are based on an interim PJM 2025 load forecast model.

The ELCC volatility also affects the reliability requirement calculation. Table 5-15 shows the reliability requirement calculation for the 2025/2026 RPM Base Residual Auction and the update for the Third Incremental Auction for 2025/2026. The pool wide accredited UCAP factor for the Third IA is based on the January 23, 2025, ELCC ratings which use the PJM 2024 load forecast model. These updated ELCC ratings reduced the pool wide accredited UCAP factor from 0.7969 to 0.7963. The reliability requirement and the FRR obligation both increase, resulting in an increase of 395.7 MW (UCAP) to the reliability requirement adjusted for FRR. PJM needs to procure an additional 395.7 MW (UCAP) of capacity in the Third Incremental Auction.

Table 5-15 PJM Reliability Requirement[132 133 134]

	2025/2026 Base Residual Auction	2025/2026 Third Incremental Auction	Change
ICAP	191,693.0	188,920.0	
Solved Load	160,624.0	158,357.0	(2,267.0)
Installed Reserve Margin	17.800%	17.800%	0.0%
Accredited UCAP	152,765.0	150,438.0	(2,327.0)
Pool Wide Accredited UCAP Factor	0.797	0.796	(0.001)
Forecast Pool Requirement	0.939	0.938	(0.001)
Preliminary Forecast Peak Load	153,883.0	154,534.1	651.0
Reliability Requirement	144,450.0	144,953.0	503.0
Fixed Resource Requirement (FRR)	10,886.4	10,993.7	107.3
Reliability Requirement Adjusted for FRR	133,563.6	133,959.3	395.7

PJM filed tariff changes that transfer risk caused by the volatile ELCC ratings from generation owners to the load. ELCC ratings may increase or decrease significantly between the time a generator clears in the RPM Base Residual Auction and the final ELCC rating just prior to the start of the delivery year. Under the new tariff rules, generators will be excused from paying the Capacity Resource Deficiency Charge for a deficiency caused by a decrease in the final ELCC rating. Under the prior rules, a Capacity Market Seller was required to cover its short position by acquiring additional capacity or pay a deficiency penalty equal to 20 percent of the base residual auction clearing price for each MW of shortage. The tariff change was filed by PJM on April 18, 2025, and approved by FERC on June 17, 2025.[135] [136] The MMU opposed the change because the new rule does not mitigate the risk as asserted by PJM but simply transfers the ELCC rating volatility risk to the load.[137] The change is inconsistent with basic market logic under which investors bear the risk associated with the ownership of generation.

PJM has calculated and posted marginal ELCC ratings on nine occasions for the 2025/2026 through 2027/2028 Delivery Years. Figure 5-5 shows the ELCC class ratings for intermittent resources. The horizontal axis shows the delivery year to which the ratings apply and the month the ratings were posted. The ratings change each time they are recalculated. The original rating for onshore wind for the 2025/2026 Delivery Year was 21 percent and the final rating for 2025/2026 Delivery year was 38 percent, an 80.9 percent increase. The onshore wind rating for the 2027/2028 Delivery Year is 41 percent, a 95.2 percent increase over the initial 2025/2026 rating. Solar has decreased. Solar with tracking technology has decreased from the initial 2025/2026 rating of 25 percent to 8 percent for the 2027/2028 Delivery Year, a 68.0 percent decrease. Solar with fixed panels has decreased 53.3 percent over the same period.

132 *2025/2026 RPM 3rd Incremental Auction Planning Parameters*, PJM Interconnection L.L.C. (January 31, 2025) <https://www.pjm.com/markets-and-operations/rpm>.
133 *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for BRA* at 15, Item 5, PJM Markets & Reliability Committee meeting, PJM Interconnection L.L.C. (March 20, 2024). <https://www.pjm.com/committees-and-groups/committees/mrc>
134 *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC)* for 3IA at 7, Item 3, PJM Members Committee meeting, PJM Interconnection L.L.C. (January 23, 2025). <https://www.pjm.com/committees-and-groups/committees/mc>
135 *Proposal to Mitigate Impacts From Updates to ELCC Accreditation between the Base Residual Auction and the Final ELCC Accreditation Values*, PJM Interconnection L.L.C., Docket ER25-2002 (April 18, 2025).
136 191 FERC ¶ 61,203 (June 17, 2025).
137 See *Comments of the Independent Market Monitor for PJM* (May 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 16, 2025), Docket ER25-2002-000).

Figure 5-5 Marginal ELCC Class Ratings for Intermittent Resources

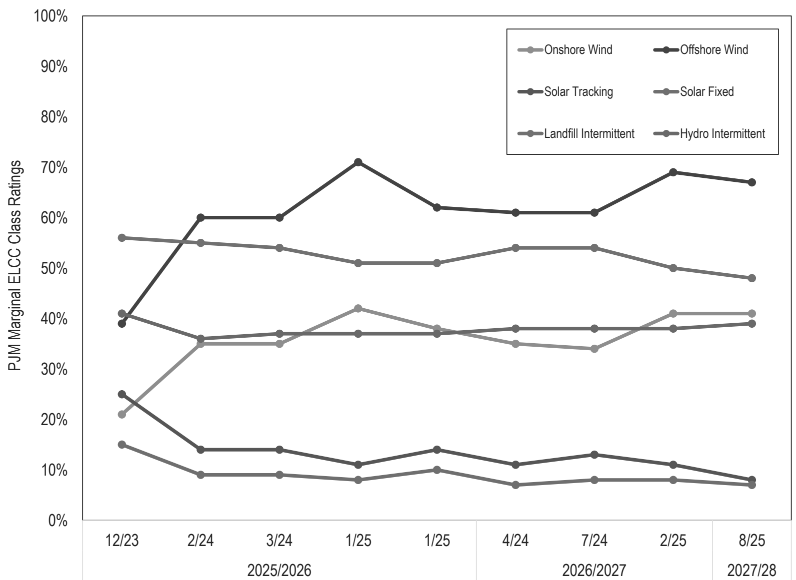
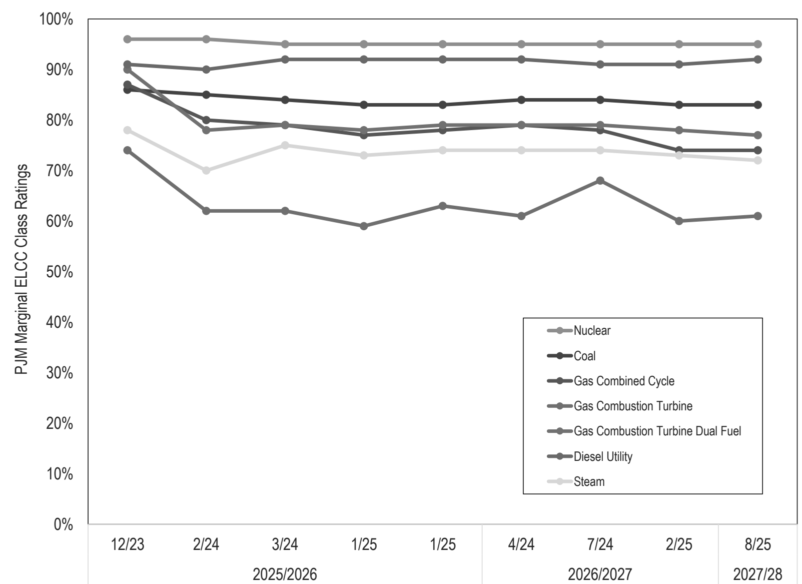


Figure 5-6 shows the ELCC rating for thermal resources. Combined cycle resource and combustion turbine ratings have decreased from their initial 2025/2026 ratings. The original rating for combined cycle resources for the 2025/2026 Delivery Year was 87 percent and the final rating for 2025/2026 Delivery Year was 78 percent, a 10.3 percent decrease. The combined cycle rating for the 2027/2028 Delivery Year is 74 percent, a 14.9 percent decrease over the initial 2025/2026 rating. Combustion turbine ratings have also decreased. Ratings for combustion turbines with dual fuel capability have decreased from the initial 2025/2026 rating of 90 percent to 77 percent for the 2027/2028 Delivery Year, a 14.4 percent decrease. Ratings for combustion turbines without dual fuel capability have decreased 17.6 percent over the same period. The change in UCAP for combined cycle and combustion turbine resources from the initial 2025/2026 ELCC ratings to the latest 2027/2028 ratings is a decrease of 11.5 GW. The corresponding change in ICAP is a decrease of 1.2 GW.

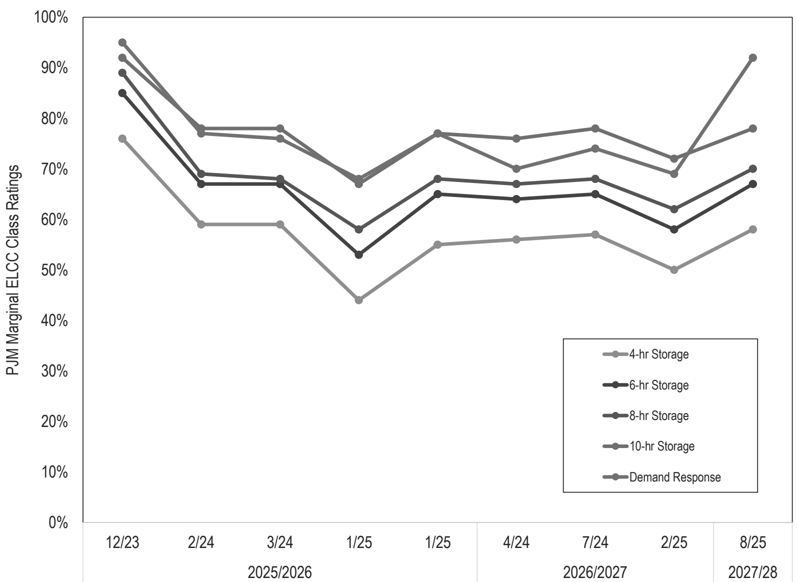
PJM could partially offset this loss of capacity in the short run by recognizing the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

Figure 5-6 Marginal ELCC Class Ratings for Thermal Resources



Marginal ELCC ratings for storage and demand response resources have also exhibited volatility. Figure 5-7 shows that the storage resource ratings have decreased. On average across all durations, storage ELCC ratings have decreased 20.4 percent from the initial 2025/2026 Delivery Year ratings to the 2027/2028 Delivery Year ratings. The initial rating for demand response for the 2025/2026 Delivery Year was 95 percent and final rating for the 2025/2026 Delivery Year was 77 percent, an 18.9 percent decrease. Due to recent rule change, the demand response rating for the 2027/2028 Delivery Year is 92 percent.[138]

Figure 5-7 Marginal ELCC Class Ratings for Storage and Demand Resources



138 191 FERC ¶61,103 (May 5, 2025).

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[139] [140] [141] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps were defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[142] The Commission rejected an attempt by PJM to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[143] The Commission approved changes to the Market Seller Offer Cap that allow Capacity Market Sellers to offer the higher of the net ACR and the Capacity Performance Quantifiable Risk (CPQR)[144] and to submit resource specific segmented offer caps.[145] Both changes to the Market Seller Offer Cap give Capacity Market Sellers the ability to offer in excess of the competitive offer and exercise market power as a result.

For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for

139 See OATT Attachment DD § 6.5.
140 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
141 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
142 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023), *cert. denied*.
143 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).
144 190 FERC ¶ 61,117 (February 20, 2025).
145 Id. at 123.

the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[146] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[147] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts, including RECs, and expected bonus performance payments/nonperformance charges.[148] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for auctions for delivery years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM tariff.[149]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[150] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[151] For standalone CPQR, the offer cap is defined as the unit specific CPQR with no net revenue offset applied. For segmented unit specific offer caps, the capacity market seller can request that the first segment of the segmented unit specific offer cap be based on either unit specific standalone CPQR or net unit specific ACR. The remaining segments from the second segment up to the tenth segment are defined to be based on standalone CPQR.[152]

Allowing offers based on gross CPQR when net revenues are greater than total gross ACR, including CPQR, permits offers greater than the competitive level by allowing resources with a competitive offer of $0 per MW-day to make positive offers equal to one component of ACR, the gross CPQR component,

146 OATT Attachment DD § 6.8(b).
147 *PJM Interconnection L.L.C., Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery* (February 14, 2019).
148 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
149 OATT Attachment DD § 6.8(a).
150 151 FERC ¶ 61,208 (2015).
151 190 FERC ¶ 61,117 (2025).
152 OATT Attachment DD § 6.4(e)

ignoring net revenues entirely. The rule also permits offers greater than the competitive level by allowing resources with a competitive offer greater than $0 per MW-day but less than gross CPQR to make offers equal to one standalone component of ACR, the gross CPQR component, also ignoring EAS entirely.

The decision to allow segmented offer caps means allowing the exercise of market power. This is the case first because the segmented offer caps require that all avoidable costs be spread over a first MW segment that is smaller than the full resource, thus inflating the MSOC, and allow offer caps for all segments after the first segment based on gross CPQR with no net revenue offsets. If avoidable costs can be assigned to the first, self defined MW offer segment, and the later MW segments are not defined in the rules, MSOCs are meaningless. Assigning gross CPQRs and no net revenues to one or more undefined MW tail blocks would permit offers that exceed the correctly calculated MSOC by multiples and would permit the exercise of market power. The rule does not use any net revenue offset for the CPQR segments. The competitive level is defined as total gross avoidable costs, net of net revenues, divided by the total MW in the offer.

On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM.[153] As a result, effective with the 2026/2027 Delivery Year, reactive revenues will not be included in the net revenue offset for RPM purposes including the VRR curve, market seller offer caps, and MOPR floors.[154]

Competitive Offers

The competitive offer of a capacity resource is based, regardless of tariff requirements, on a market seller's expectations of the resource's net going forward costs (net ACR) which are the net of the resource's gross ACR and the resource's forward looking net revenues. The gross ACR includes the cost to mitigate the resource's risk of incurring performance assessment penalties (CPQR).

153 *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024) ("Order No. 904").
154 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).

The competitive offer is based on a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel prices are a better guide to market expectations than historical energy and fuel prices but both sources of information should be incorporated. This is particularly important in years, like 2022, when there is a significant change from the historical level of energy market prices. The forward curves reflect this change, but the historical prices do not. However, the PJM method for calculating forward looking net revenues is significantly flawed and overestimates net revenues.

PJM had a forward looking net revenue calculation in the tariff that applied to RPM Auctions for the 2022/2023 Delivery Year.[155] FERC subsequently reversed its approval of that method as part of rejecting PJM's ORDC filing.[156] PJM's method for calculating forward looking E&AS net revenues was flawed for several reasons. PJM's method included an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. It would be simpler, more accurate and more transparent to use forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the

155 171 FERC ¶ 61,153 (May 21, 2020) and 173 FERC ¶ 61,134 (November 12, 2020).
156 Forward energy and ancillary services (E&AS) revenue offsets were applicable from November 12, 2020, as approved in the FERC Order on compliance in Docket Nos. EL19-58-002 and EL19-58-003 until December 22, 2021, when the Commission issued an Order on Voluntary Remand in Docket Nos. EL19-58-006 and ER19-1486-003 reversing its prior determination that PJM should use a forward looking energy E&AS revenue offset and directing PJM to submit a compliance filing restoring the tariff provisions defining the historical E&AS revenue offset.

opportunity costs associated with environmental limits on the operation of generating units.[157]

More fundamentally, PJM's forward looking net revenue calculation tends to overestimate forward net revenues. The PJM method is based on a theoretical, unit by unit perfect dispatch based on unit parameters and forward fuel costs and LMPs. The PJM method fails to account for the realities of committing and dispatching units. Nonetheless, it remains correct that generation owners look forward and not backwards when calculating net revenues. The goal is an approach that retains the reality of historical commitment and dispatch while recognizing that future conditions will be different. A better approach would calculate unit forward looking expected energy and ancillary services net revenues using historical revenues that are scaled based on a comparison of forward prices for energy and fuel to the historical prices for energy and fuel.

The competitive offer of a capacity resource is based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[158]

The September 2, 2021, Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR.[159] The Commission rejected a more recent attempt by PJM to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[160]

In February 2025, PJM filed, and FERC approved, changes to the Market Seller Offer Cap that allow Capacity Market Sellers to offer the higher of the net ACR and the Capacity Performance Quantifiable Risk (CPQR).[161] The changes also allow Capacity Market Sellers to submit resource specific segmented offer caps.[162] Both changes to the Market Seller Offer Cap give Capacity Market Sellers the ability to offer in excess of the competitive offer.

Allowing offers based on gross CPQR when net revenues are greater than total gross ACR, including CPQR, permits offers greater than the competitive level by allowing resources with a competitive offer of $0 per MW-day to make positive offers equal to one component of ACR, the gross CPQR component, ignoring net revenues entirely. The rule also permits offers greater than the competitive level by allowing resources with a competitive offer greater than $0 per MW-day but less than gross CPQR to make offers equal to one standalone component of ACR, the gross CPQR component, also ignoring EAS entirely.

The decision to allow segmented offer caps means allowing the exercise of market power. This is the case first because the segmented offer caps require that all avoidable costs be spread over a first MW segment that is smaller than the full resource, thus inflating the MSOC, and allow offer caps for all segments after the first segment based on gross CPQR with no net revenue offsets. If avoidable costs can be assigned to the first, self defined MW offer segment, and the later MW segments are not defined in the rules, MSOCs are meaningless. Assigning gross CPQRs and no net revenues to one or more undefined MW tail blocks would permit offers that exceed the correctly calculated MSOC by multiples and would permit the exercise of market power.

157 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 46 (Nov. 25, 2024).
158 OATT Attachment DD § 10A (d).
159 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023).
160 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).
161 190 FERC ¶ 61,117 (February 20, 2025).
162 Id. at 123.

The rule does not use any net revenue offset for the CPQR segments. The competitive level is defined as total gross avoidable costs, net of net revenues, divided by the total MW in the offer.

2025/2026 RPM Third Incremental Auction

As shown in Table 5-16, 307 generation resources submitted Capacity Performance offers in the 2025/2026 RPM Third Incremental Auction. Unit specific offer caps were calculated for two generation resources (0.7 percent). Of the 307 generation resources, 238 generation resources elected the offer cap option of 1.1 times the BRA clearing price (77.5 percent), five generation resources had default ACR based offer caps (1.6 percent), two generation resource had a unit specific opportunity cost based offer cap (0.7 percent), five Planned Generation Capacity Resources had uncapped offers (1.6 percent), and the remaining 57 generation resources were price takers (18.6 percent). Market power mitigation was applied to zero Capacity Performance sell offers.

2026/2027 RPM Base Residual Auction

As shown in Table 5-16, 1,293 generation resources submitted Capacity Performance offers in the 2026/2027 RPM Base Residual Auction. Unit specific offer caps were calculated for 82 generation resources (6.3 percent). Of the 1,293 generation resources, 735 generation resources had default ACR based offer caps (56.8 percent), 26 generation resources had unit specific ACR based offer caps (2.1 percent), 48 resources had unit specific standalone CPQR offer caps (3.7 percent), 6 generation resources had unit specific opportunity cost based offer caps (0.5 percent), 2 generation resources had unit specific opportunity cost based offer caps and default ACR based offer caps (0.2 percent), 26 Planned Generation Capacity Resources had uncapped offers (2.0 percent), and the remaining 450 generation resources were price takers (34.8 percent). Market power mitigation was applied to 23 Capacity Performance sell offers.

Table 5-16 ACR statistics: RPM auctions held through the first nine months, 2025

	2025/2026 Third Incremental Auction		2026/2027 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	5	1.6%	735	56.8%
Unit specific ACR (APIR)	0	0.0%	4	0.3%
Unit specific ACR (APIR and CPQR)	0	0.0%	2	0.2%
Unit specific ACR (non-APIR)	0	0.0%	2	0.2%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	18	1.4%
Unit specific standalone CPQR	NA	NA	48	3.7%
Unit specific segmented offer caps	NA	NA	0	0.0%
Opportunity cost input	2	0.7%	6	0.5%
Default ACR and opportunity cost	0	0.0%	2	0.2%
Offer cap of 1.1 times BRA clearing price elected	238	77.5%	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%	NA	NA
Uncapped planned generation resources	5	1.6%	26	2.0%
Existing generation resources as price takers	57	18.6%	450	34.8%
Total Generation Capacity Resources offered	307	100.0%	1,293	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[163] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative approaches.[164] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[165]

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[166] The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

163 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020), *aff'd* PJM Power Providers Group, et al. v. FERC, Case No. 21-3068 (3rd Cir. December 1, 2023), *cert denied.*
164 Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).
165 *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).
166 *PJM Interconnection, L.L.C*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[167]

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking E&AS offset to include forward looking energy and ancillary services revenues rather than historical. The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2023/2024 BRA. This decision was reversed in the Commission's order related to the ORDC matter.

MOPR Statistics

Under the applicable MOPR rules, market power mitigation measures were applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-17, there were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2) for the 2025/2026 RPM Third Incremental Auction or for the 2026/2027 RPM Base Residual Auction. Of the 583.9 MW offered in the 2025/2026 RPM Third Incremental Auction that were subject to MOPR, 583.9 MW cleared and 0.0 MW did not clear. Of the 267.6 MW offered in the 2026/2027 RPM Base Residual Auction that were subject to MOPR, 237.4 MW cleared and 30.2 MW did not clear.

167 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).

Table 5-17 MOPR statistics: RPM auctions held through the first nine months, 2025

			Number of	ICAP (MW)			UCAP (MW)	
	MOPR Type	Calculation Type	Requests	Requested	MMU Agreed	Offered	Offered	Cleared
2025/2026 Third Incremental Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	823.2	583.9	583.9
	Total		0	0.0	0.0	823.2	583.9	583.9
2026/2027 Base Residual Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	600.9	267.6	237.4
			0	0.0	0.0	600.9	267.6	237.4

Replacement Capacity[168]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-18 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2026.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are

168 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation.

Table 5-18 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2025

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	150,465.2	0.0	(5,576.9)	144,888.3	(1,212.7)	143,675.6
01-Jun-23	150,143.9	0.0	(5,517.6)	144,626.3	(2,363.5)	142,262.8
01-Jun-24	154,362.5	0.0	(4,046.2)	150,316.3	(4,377.2)	145,939.1
01-Jun-25	137,733.6	0.0	(1,812.6)	135,921.0	(934.8)	134,986.2
01-Jun-26	134,205.3	0.0	0.0	134,205.3	0.0	134,205.3

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-19 shows RPM clearing prices for the 2021/2022 through 2026/2027 Delivery Years for all RPM auctions held through the first nine months of 2025, and Table 5-20 shows the RPM cleared MW for the 2021/2022 through 2026/2027 Delivery Years for all RPM auctions held through the first nine months of 2025.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA from the 2022/2023 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through the first nine months of 2025. A summary of these weighted average prices is given in Table 5-21.

Table 5-22 shows RPM revenue by delivery year for all RPM auctions held through the first nine months of 2025 based on the unforced MW cleared and the resource clearing prices. For the 2024/2025 Delivery Year, RPM revenue is $2.6 billion. For the 2025/2026 Delivery Year, RPM revenue is $14.9 billion.

Table 5-23 shows RPM revenue by calendar year for all RPM auctions held through the first nine months of 2025. In 2024, RPM revenue is $2.5 billion. In 2025, RPM revenue is $9.8 billion.

Table 5-24 shows the RPM annual charges to load. For the 2024/2025 Delivery Year, annual charges to load are $2.5 billion. For the 2025/2026 Delivery Year, annual charges to load are $14.8 billion.

Table 5-19 Capacity market clearing prices: 2021/2022 through 2026/2027 RPM Auctions[169]

		RPM Clearing Price ($ per MW-day)														
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	DOM
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55	$20.55
2022/2023 BRA	Capacity Performance	$50.00	$95.79	$50.00	$95.79	$97.86	$95.97	$97.86	$97.86	$97.86	$95.79	$50.00	$68.96	$126.50	$71.69	$50.00
2022/2023 Third Incremental Auction	Capacity Performance	$19.00	$35.00	$19.00	$35.00	$35.00	$96.15	$35.00	$35.00	$35.00	$35.00	$19.00	$19.00	$35.00	$19.00	$19.00
2023/2024 BRA	Capacity Performance	$34.13	$49.49	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$49.49	$49.49	$34.13	$34.13	$69.95	$34.13	$34.13
2023/2024 Third Incremental Auction	Capacity Performance	$37.53	$49.49	$37.53	$49.49	$146.03	$49.49	$146.03	$146.03	$146.03	$49.49	$37.53	$37.53	$79.03	$37.53	$37.53
2024/2025 BRA	Capacity Performance	$28.92	$49.49	$28.92	$49.49	$53.60	$49.49	$426.17	$53.60	$53.60	$49.49	$28.92	$28.92	$73.00	$96.24	$28.92
2024/2025 Third Incremental Auction	Capacity Performance	$58.00	$80.00	$58.00	$80.00	$175.81	$80.00	$175.81	$175.81	$175.81	$80.00	$58.00	$58.00	$155.29	$58.00	$58.00
2025/2026 BRA	Capacity Performance	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$466.35	$269.92	$444.26
2025/2026 Third Incremental Auction	Capacity Performance	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$559.64	$323.90	$323.90
2026/2027 BRA	Capacity Performance	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17

Table 5-20 Capacity market cleared MW: 2021/2022 through 2026/2027 RPM Auctions[170]

		UCAP (MW)														
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	DOM	TOTAL
2021/2022	BASE	26,552.8	12,565.1	10,136.1	15,368.6	22,286.8	1,673.8	2,237.7	3,134.1	6,013.2	8,010.5	22,358.1	4,200.7	2,746.1	26,343.7	163,627.3
2021/2022	FIRST	118.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	75.4	2,143.2
2021/2022	SECOND	1,082.0	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	160.5	3,707.5
2021/2022	THIRD	1,243.7	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	394.7	5,235.0
2022/2023	BASE	29,596.0	12,804.7	10,147.4	14,118.7	23,651.2	1,312.9	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	8,136.3	144,477.3
2022/2023	THIRD	703.3	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	395.7	5,987.9
2023/2024	BASE	28,642.1	10,098.5	8,145.5	14,352.7	22,912.6	1,412.8	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	8,266.7	145,066.9
2023/2024	THIRD	255.9	1,786.4	395.0	79.3	671.0	24.2	32.4	43.8	15.3	355.8	1,050.0	240.0	68.4	59.8	5,077.0
2024/2025	BASE	28,760.7	10,854.4	8,874.0	14,178.1	23,135.1	1,448.6	2,665.3	3,494.3	3,429.7	9,720.6	25,156.1	5,056.5	2,062.1	8,646.1	147,481.5
2024/2025	THIRD	365.3	744.8	815.6	665.2	963.0	33.2	48.7	60.2	78.7	245.6	2,370.0	222.5	90.2	177.9	6,881.0
2025/2026	BRA	24,573.1	9,490.1	8,481.3	12,368.8	19,043.0	958.7	1,894.3	2,520.1	2,274.4	7,778.5	21,814.2	2,800.6	1,636.7	20,050.2	135,684.0
2025/2026	THIRD	731.3	22.2	90.8	31.9	564.8	26.1	9.0	34.7	79.4	177.2	91.5	8.3	19.8	162.7	2,049.6
2026/2027	BRA	24,888.5	9,213.7	8,476.5	11,939.7	16,318.1	998.0	1,725.3	2,361.6	2,170.2	7,433.9	20,273.0	4,319.1	1,560.1	19,984.8	134,205.3

169 See Appendix L for a complete table of historic capacity prices.
170 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-21 Weighted average clearing prices by zone: 2023/2024 through 2026/2027

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2023/2024	2024/2025	2025/2026	2026/2027
RTO				
AEP	$34.21	$29.80	$270.57	$329.17
APS	$34.21	$29.80	$270.57	$329.17
ATSI	$34.26	$29.80	$271.18	$329.17
Cleveland	$34.21	$28.92	$270.90	$329.17
COMED	$34.27	$31.42	$270.15	$329.17
DAY	$34.17	$29.13	$295.05	$329.17
DUKE	$34.24	$94.57	$270.57	$329.17
DUQ	$34.21	$29.80	$270.57	$329.17
DOM	$34.21	$29.80	$443.29	$329.17
EKPC	$34.21	$29.80	$270.57	$329.17
MAAC				
EMAAC				
ACEC	$52.21	$58.47	$271.47	$329.17
DPL	$52.21	$58.47	$271.47	$329.17
DPL South	$71.26	$420.55	$271.35	$329.17
JCPLC	$52.21	$58.47	$271.47	$329.17
PECO	$52.21	$58.47	$271.47	$329.17
PSEG	$50.71	$55.54	$270.17	$329.17
PSEG North	$50.73	$55.48	$270.65	$329.17
REC	$52.21	$58.47	$271.47	$329.17
SWMAAC				
BGE	$70.65	$77.88	$466.64	$329.17
PEPCO	$49.46	$50.12	$271.74	$329.17
WMAAC				
MEC	$49.49	$51.07	$270.01	$329.17
PE	$49.49	$51.07	$270.01	$329.17
PPL	$49.49	$51.18	$270.12	$329.17

Table 5-22 RPM revenue by delivery year: 2007/2008 through 2026/2027[171]

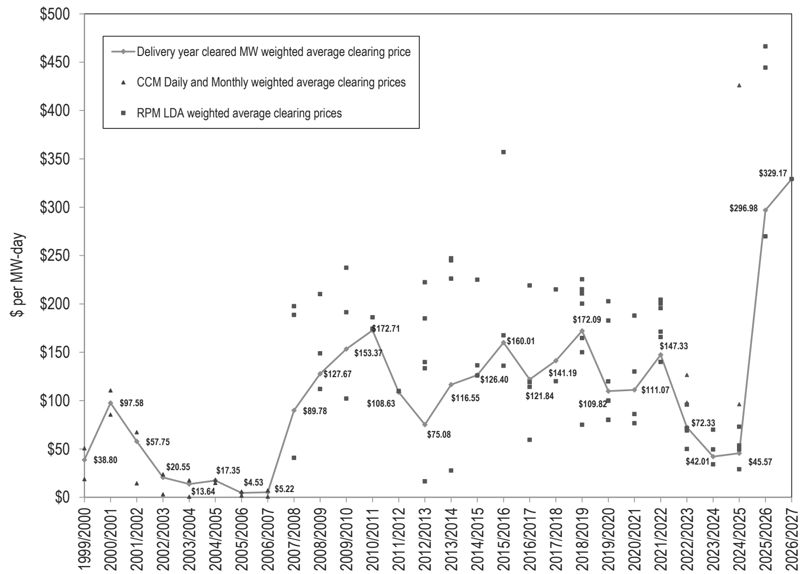
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$72.33	150,465.2	365	$3,972,428,671
2023/2024	$42.01	150,143.9	366	$2,308,670,914
2024/2025	$45.57	154,362.5	365	$2,567,491,013
2025/2026	$296.98	137,733.6	365	$14,930,072,430
2026/2027	$329.17	134,205.3	365	$16,124,370,889

171 The results for the ATSI Integration Auctions are not included in this table.

Table 5-23 RPM revenue by calendar year: 2007 through 2027[172]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$103.36	160,496.5	365	$6,215,973,960
2023	$54.56	150,036.3	365	$2,993,266,921
2024	$44.09	152,857.8	366	$2,464,115,790
2025	$192.97	144,613.0	365	$9,815,689,432
2026	$315.85	135,665.0	365	$15,630,291,253
2027	$329.17	55,520.5	151	$6,670,630,149

Figure 5-8 History of capacity prices: 1999/2000 through 2026/2027[173]



172 The results for the ATSI Integration Auctions are not included in this table.

173 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2025/2026 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-9 Map of RPM capacity prices: 2023/2024 through 2026/2027

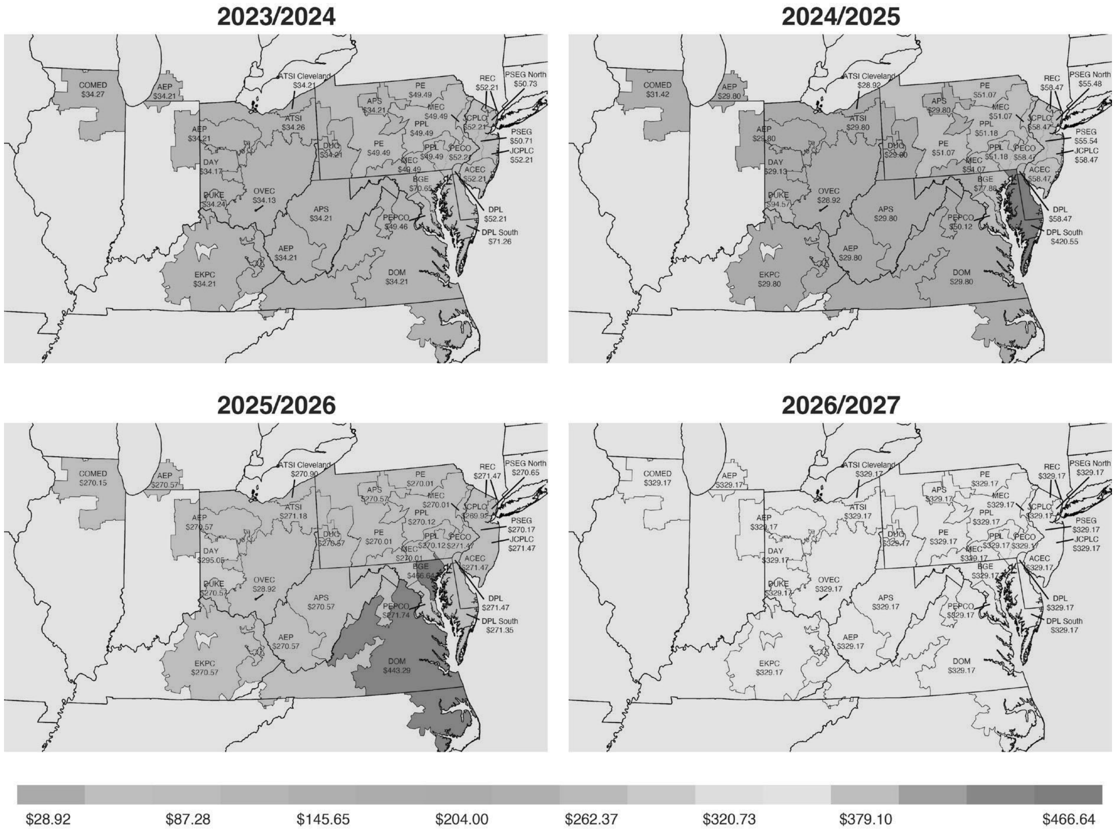


Table 5-24 RPM cost to load: 2023/2024 through 2026/2027 RPM Auctions[174 175]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2023/2024			
Rest of RTO	$34.18	78,896.5	$986,982,057
EMAAC	$50.96	30,972.7	$577,657,195
WMAAC	$49.58	22,401.9	$406,535,572
Rest of EMAAC	$57.19	4,375.0	$91,582,753
BGE	$59.38	7,496.6	$162,936,916
Total		144,142.8	$2,225,694,492
2024/2025			
Rest of RTO	$29.50	77,398.7	$833,520,097
EMAAC	$56.56	32,270.3	$666,184,144
WMAAC	$50.22	22,872.2	$419,263,035
Rest of EMAAC	$175.22	4,590.0	$293,561,344
BGE	$61.53	7,726.0	$173,527,700
DEOK	$57.93	5,254.4	$111,105,639
Total		150,111.7	$2,497,161,960
2025/2026			
Rest of RTO	$270.43	108,328.9	$10,692,932,080
BGE	$306.84	6,005.7	$672,628,585
DOM	$432.48	21,570.5	$3,405,010,751
		135,905.1	$14,770,571,416
2026/2027			
Rest of RTO	$329.17	134,205.3	$16,124,370,889
		134,205.3	$16,124,370,889

174 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.
175 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[176 177 178 179 180 181] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

176 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).
177 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).
178 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).
179 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).
180 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).
181 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the prior MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

Dominion Energy Virginia elected the FRR option for the 2022/2023 through 2024/2025 Delivery Years but returned to the capacity market for the 2025/2026 BRA.

CRF Issue[182]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct. These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[183] In the filing, PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[184] [185]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\sum_{\mathrm{j}=1}^{\mathrm{L}}\frac{\mathrm{m_j}}{(1+\mathrm{r})^{\mathrm{j}}}\right]}{(1-s)\sqrt{1+\mathrm{r}}\,[(1+r)^N - 1]}$$

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the CRF formula be included in the tariff.[186] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-26 shows the CRFs that are currently posted. The values in Table 5-26 were calculated using the formula above and the financial assumptions in Table 5-27. Bonus depreciation assumptions vary by delivery year with

182 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).
183 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket No. ER21-1844-000 (May 4, 2021).
184 See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).
185 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket No. ER21-1635-000.
186 176 FERC ¶61,003 (2021).

100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-25 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
mj	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

The MMU supports the changes to the tariff to correct the application of CRF to the capacity market but there are still unresolved issues. The tariff revisions lack clarity about how CRF values will be determined in the future and to which projects they apply, and lack clarity about how CRF values would be applied to APIR for project costs that are currently being recovered. For example, Table 5-26, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.[187] For example, a project that can use the depreciation provisions relevant for the 2023/2024 Delivery Year uses the depreciation provisions once and those provisions affect the project's CRF for its entire life, regardless of the CRF values in the table for subsequent delivery years. However, changes in the tax rate apply each year and if the tax rate changes the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-26 for delivery years after 2023/2024 would not apply to the calculation of APIR values for projects that go into service for the 2023/2024 Delivery Year. A similar issue exists for projects that were assigned a CRF under the previous tariff rules. The change in the tax rate should be reflected in the CRF going forward. PJM does not plan to do this and the Commission stated that the issue is beyond the scope of the PJM filing.[188]

187 See "Capital Recovery Factors ("CRF") for Avoidable Project Investment Cost ("APIR") Determinations," <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/crf-values-for-apir-determination.ashx>.
188 176 FERC ¶61,003 at P 28 (2021).

On July 4, 2025, with the enactment of the One Big Beautiful Bill Act ("OBBBA"), the bonus depreciation rules changed again. Section 70301 of OBBBA (I.R.C. § 168(k)) allows 100 percent bonus depreciation for "qualified production property ("QPP") acquired and placed in service on or after January 20, 2025.[189] QPP means nonresidential real property used in manufacturing, production, or refining of tangible personal property in the United States.[190] To be eligible, construction must begin after January 19, 2025, and before January 1, 2029, and the property must be placed in service before January 1, 2031.[191] The formula rate calculation of the CRF values in Paragraph 18 of OATT Schedule 6A for units entering service after June 6, 2021, must be implemented to reflect the correct bonus depreciation. It is essential that PJM not repeat its earlier mistake when it ignored the tax law changes in 2017.

Table 5-26 Levelized CRF values: Delivery Year 2023/2024 through Delivery Year 2026/2027

	Cost	2023/2024	2024/2025	2025/2026	2026/2027
Age of Unit	Recovery	Bonus Depreciation Percent			
(Years)	Period	80%	60%	100%	100%
1 to 5	30	0.091	0.094	0.088	0.093
6 to 10	25	0.096	0.098	0.093	0.098
11 to 15	20	0.104	0.107	0.101	0.105
16 to 20	15	0.119	0.122	0.116	0.120
21 to 25	10	0.152	0.158	0.147	0.151
25 Plus	5	0.258	0.271	0.246	0.249
Mandatory CapEx	4	0.312	0.328	0.296	0.300
40 Plus Alternative	1	1.100	1.100	1.100	1.100

Table 5-27 Financial parameter and tax rate assumptions for CRF calculations

	Parameter Values	
Parameter	Prior to 2026/2027	2026/2027
Equity Funding Percent	45.000%	45.000%
Debt Funding Percent	55.000%	55.000%
Equity Rate	13.000%	14.100%
Debt Interest Rate	6.000%	6.300%
Federal Income Tax Rate	21.000%	21.000%
State Income Tax Rate	9.300%	9.933%
Effective Income Tax Rate	28.347%	28.847%
After Tax Weighted Average Cost of Capital	8.215%	8.810%

189 OBBBA § 70301(c)(1).
190 OBBBA § 70307(a)(2).
191 *Id.*

The 2021 update to the CRF values was calculated using the weighted average cost of capital (WACC) model. The original CRF values, prior to 2021, were calculated using a flow to equity (FTE) model. The WACC model assumes a constant debt to equity ratio during the capital recovery period and therefore assumes that debt holders are paid more quickly than is required. The FTE model recognizes that the debt is repaid according to a predetermined payment schedule with all revenue in excess of taxes and debt payments going to the equity investor. The FTE model accurately reflects the cash flows that occur during capital recovery. Table 5-28 compares CRFs calculated under the two approaches using the assumptions in Table 5-27. The difference between the WACC CRF and FTE CRF is dependent upon the capital recovery term and the level of bonus depreciation. The WACC CRF exceeds the FTE CRF by 16.4 percent under 100 percent bonus depreciation with a 30 year cost recovery term. The FTE model is the correct approach because it accurately captures the cash flows during capital recovery over the defined financial life of the asset.

Table 5-28 Comparison of FTE and WACC CRFs

	WACC CRF						FTE CRF					
Capital Recovery	Bonus Percent						Bonus Percent					
Term (years)	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.296	0.312	0.328	0.345	0.361	0.377	0.289	0.307	0.324	0.342	0.360	0.377
5	0.246	0.258	0.271	0.283	0.296	0.308	0.238	0.252	0.266	0.280	0.294	0.308
10	0.147	0.152	0.158	0.164	0.169	0.175	0.138	0.145	0.153	0.160	0.168	0.175
15	0.116	0.119	0.122	0.126	0.129	0.132	0.105	0.111	0.116	0.122	0.127	0.133
20	0.101	0.104	0.107	0.110	0.113	0.115	0.090	0.095	0.100	0.105	0.110	0.115
25	0.093	0.096	0.098	0.101	0.104	0.106	0.081	0.086	0.091	0.096	0.100	0.105
30	0.088	0.091	0.094	0.096	0.099	0.101	0.076	0.081	0.085	0.090	0.095	0.099

	Absolute Change (WACC CRF less FTE CRF)						Relative Change					
Capital Recovery	Bonus Percent						Bonus Percent					
Term (years)	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.007	0.005	0.004	0.003	0.001	0.000	2.3%	1.8%	1.2%	0.8%	0.3%	(0.1%)
5	0.007	0.006	0.004	0.003	0.001	0.000	3.1%	2.3%	1.6%	1.0%	0.4%	(0.1%)
10	0.009	0.007	0.005	0.003	0.002	0.000	6.5%	4.9%	3.4%	2.1%	0.9%	(0.2%)
15	0.010	0.008	0.006	0.004	0.002	0.000	9.5%	7.2%	5.0%	3.1%	1.3%	(0.3%)
20	0.011	0.009	0.007	0.005	0.003	0.000	12.2%	9.3%	6.7%	4.4%	2.3%	0.4%
25	0.012	0.010	0.007	0.005	0.003	0.001	14.4%	11.2%	8.2%	5.6%	3.2%	1.1%
30	0.012	0.010	0.008	0.006	0.004	0.002	16.4%	12.8%	9.6%	6.7%	4.1%	1.7%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU prior to the proposed deactivation date. Prior to September 2022, generation owners were required to provide deactivation notices at least 90 days before the proposed deactivation date. Beginning in September 2022, PJM and the MMU began reviewing deactivation requests quarterly, and the desired deactivation date is now based on the quarter the request was submitted (Table 5-29). The result is no change to the effective period between the notice and the retirement if notice is provided on the last day of the submittal period, and an increase to six months notice if notice is given on the first day of the submittal period. The MMU recommends that participants be required to provide a notice of deactivation 12 months prior to an auction in which the unit will not be offered due to the deactivation; and no less than 12 months prior to the date of deactivation.

Table 5-29 Earliest deactivation dates allowed based on quarterly submission

Date Request Submitted	Earliest Deactivation Date Permitted
January 1 to March 31	July 1
April 1 to June 30	October 1
July 1 to September 30	January 1 (following calendar year)
October 1 to December 31	April 1 (following calendar year)

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[192] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[193]

Table 5-30 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through September 2025. Of the 222 deactivation requests submitted, 32 units (14.4 percent) deactivated an average of 153 days earlier than their initially requested date; 34 units (15.3 percent) deactivated an average of 120 days later than the originally requested deactivation date; and 87 units (39.2 percent) deactivated on their initially requested date. Thirty six (16.2 percent) of the unit deactivations were cancelled an average of 298 days (approximately 42 weeks) before their scheduled deactivation date, and 33 (14.9 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-31 shows this information broken out by fuel types.

Due to the significant increase in the capacity price for the 2025/2026 Delivery Year, several units that were scheduled to deactivate rescinded their deactivation request. In 2024, Middle River Power, LLC, rescinded the deactivation of 483 MW from the Elgin CT 1-4 units. In the first nine months of 2025, 11 other units that were slated to deactivate (108 MW from Gen On Energy Management, LLC rescinding Morgantown CT 3 & 4; 54.9 MW from Constellation Energy Co. rescinding Perryman 6 unit 1; 15 MW from Tenaska Power Services, Co. rescinding Kenilworth; 272.1 MW from NRG Business Marketing LLC rescinding Fisk CT 31- 34 and Waukegan CT 31 & 32), accounting for 450.0 MW, rescinded their deactivation requests as a result of the 2025/2026 BRA clearing prices.

Table 5-30 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through September 2025[194]

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	32	14.4%	(153)
Late	34	15.3%	120
On time	87	39.2%	0
Cancelled	36	16.2%	(298)
Pending	33	14.9%	-
Total	222	100.0%	-

192 OATT Attachment DD § 6.6(g).
193 OATT Part V §113.
194 Negative values indicate the average number of days the action is taken prior to the requested date.

Table 5-31 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through September 2025

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	50.0%	(4)
	Late	1	25.0%	14
	On time	1	25.0%	-
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	4	100.0%	-
Coal	Early	15	29.4%	(169)
	Late	10	19.6%	170
	On time	16	31.4%	0
	Cancelled	4	7.8%	(371)
	Pending	6	11.8%	-
	Total	51	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	6	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	6	100.0%	-
Methane	Early	5	19.2%	(92)
	Late	7	26.9%	71
	On time	11	42.3%	0
	Cancelled	2	7.7%	(190)
	Pending	1	3.8%	-
	Total	26	100.0%	-
Natural Gas	Early	4	7.0%	(197)
	Late	8	14.0%	71
	On time	20	35.1%	0
	Cancelled	8	14.0%	(220)
	Pending	17	29.8%	-
	Total	57	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
	Total	10	100.0%	-
Oil	Early	3	5.8%	(218)
	Late	7	13.5%	188
	On time	24	46.2%	0
	Cancelled	12	23.1%	(334)
	Pending	6	11.5%	-
	Total	52	100.0%	-
Solar	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	1.9%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	1	1.9%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	1	100.0%	-
Storage	Early	3	27.3%	(157)
	Late	1	9.1%	-
	On time	7	63.6%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	11	100.0%	-

Part V Reliability Service (RMR)

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[195] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff, and the PJM market design has important distinguishing features relative to other regions where arrangements referred to as RMR are used. Here the term Part V reliability service is used. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. The current capacity market design fails to include transmission constraints inside LDAs with the result that units needed for reliability do not clear in capacity auctions and that prices are suppressed and an RMR is then required. The current approach does not adequately look forward and attempt to address foreseeable unit retirements, whether for economic or regulatory reasons. The result is the wrong price signal for either investing in the existing resource or investing in new resources to provide locational reliability. The answer is not to artificially increase prices during the RMR while the transmission alternative is under construction but to provide an actionable price signal in advance of retirement as a signal to new generation to enter and compete with the transmission solution. It is essential that the deactivation provisions of the tariff be evaluated and modified, both to provide rules that better anticipate deactivations in the markets and rules that reasonably compensate Part V reliability service if it is still needed. Recent changes to the rules fail to address these issues.[196] It is also essential that queue processes that effectively prevent competition from new generation to replace the old generation be modified.

To improve coordination of deactivations and PJM transmission system planning, the MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning which means recognizing transmission constraints inside LDAs when they create reliability issues. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. This result indicates a significant market design flaw.

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM treats RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times early in the process when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part, and there is enough time to permit such new entry. There are times later in the process when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete or when there is not enough time to permit such new entry. The relevant rules can and should be changed.[197]

The planning process should, to the extent possible, evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[198] It is essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. While not all retirements are completely foreseeable, improvement is needed

195 OATT Part V §114.

196 See Deactivation Enhancements Senior Task Force (DESTF), which can be accessed at: <https://www.pjm.com/committees-and-groups/task-forces/destf>.

197 While PJM filed for and FERC accepted the inclusion of RMR resources Brandon Shores and Wagner plants in the 2026/2027 BRA and 2027/2028 BRA, that does not require that RMR resources be included in capacity market auction clearing in future auctions for these or other RMR resources. See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).

198 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

in the process for ensuring that planning is looking at the probability of retirements, especially of resources that are critical to locational reliability in order to minimize the duration of any RMR requirement.

The actual implementation of Part V of the tariff has resulted in overpayment of the RMR resources. It is essential that the compensation provisions of Part V of the tariff be modified to ensure payment of all but only the actual costs incurred by the generation owner to provide the service, plus an incentive. Generators operating in competitive markets should be required, as an obligation of receiving interconnection service and having the ability to participate in competitive markets, to provide service under Part V on an incremental cost plus incentive basis when they are needed for reliability.

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[199] If the MMU determines that expected revenues exceed avoidable costs and therefore that the deactivation is not economic, the MMU will inform the unit owner that there is a market power issue. The MMU has no authority to prevent the retirement. The MMU can pursue the matter at FERC. Part V status by itself creates market power for the retiring resource. The owners of Part V resources have threatened to shut down the resources and put the grid at risk if they do not receive their requested level of Part V payments. Such exercises of market power have been effective in increasing payments to Part V units during the settlement proceedings that have resolved all Part V filings, generally on a black box basis.

PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[200] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to remain in service for a defined period.[201] The PJM market rules do not require an owner to remain in service. Owners must provide notice of a proposed deactivation at least twelve months prior to the desired deactivation date, although the advance notice can be too short to permit new generation to enter (See Table 5-29).[202] [203] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[204] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction based on retirement, an owner must submit a preliminary RPM must offer exception request no later than September 1 preceding the BRA and a final RPM must offer exception request demonstrating "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM no later than December 1 preceding the BRA.[205]

Under the current rules, a unit remaining in service at PJM's request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[206] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[207] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[208] The rules provide terms for the repayment of project investment by owners of units that choose to keep units in service after the defined period ends.[209] The amount of project investment recovered cannot exceed the actual amount of the PI.[210] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[211]

The DACR is unnecessarily prescriptive about the nature of the incremental costs needed to provide service, and includes unsupported escalation to extremely high incentive rates.

199 OATT § 113.2; OATT Attachment M § IV.1.
200 OATT § 113.2.
201 *Id.*
202 See Letter Order, FERC Docket No. ER25-1501-000 (April 15, 2025).
203 OATT § 113.1.
204 OATT Attachment DD § 6.6(g).
205 *Id.*
206 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Multiplier) * MW capability of the unit * Number of days in the month) + (APIR * First Year Multiplier) – Actual Net Revenues).
207 OATT § 115.
208 *Id.*
209 OATT § 118.
210 OATT §§ 115.
211 OATT § 119.

Table 5-32 shows units that have provided Part V reliability service to PJM, including the Indian River 4 unit, which began providing RMR service on June 1, 2022, and ended on February 24, 2025.[212] Only two of nine owners have used the deactivation avoidable cost rate approach. The other seven owners used the cost of service recovery rate. For units using the cost of service recovery rate option, revenues have averaged about 2.9 times the corresponding market price of capacity while for units using the deactivation avoidable cost rate, revenues have averaged about 1.6 times the corresponding market price of capacity.[213]

Table 5-32 Part V reliability service summary

Unit Names	Owner	Fuel Type	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Brandon Shores 1	Talen Energy Corporation	Coal	635.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Brandon Shores 2	Talen Energy Corporation	Coal	638.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Wagner 3	Talen Energy Corporation	Coal	305.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Wagner 4	Talen Energy Corporation	Oil	397.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Indian River 4	NRG Power Marketing LLC	Coal	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	24-Feb-25
B.L. England 2	RC Cape May Holdings, LLC	Coal	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	Coal	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	Coal	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	Oil	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	Coal	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	Coal	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	Coal	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	Coal	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	Natural gas/oil, Diesel	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	Coal	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	Natural gas	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

212 See PJM, "Informational Filing Regarding Formal Notice of Termination of Reliability Must-Run Service," Docket Nos. ER22-2539-000 and ER23-2688-000 (December 23, 2024).
213 The final rates for Brandon Shores and Wagner have not been established.

Table 5-33 Part V reliability service cost summary[214 215]

		Initial Filing		Actual		Weighted Average
Unit Names	Owner	Total Cost	Cost per MW-day	Total Cost	Cost per MW-day	RPM Clearing Price ($ per MW-day)
Brandon Shores 1	Talen Energy Corporation	$327,039,342	$393.45	$7,644,258	$130.85	$313.08
Brandon Shores 2	Talen Energy Corporation	$328,584,409	$393.45	$7,680,372	$130.85	$313.08
Wagner 3	Talen Energy Corporation	$64,791,528	$162.29	$2,505,444	$89.29	$313.08
Wagner 4	Talen Energy Corporation	$84,335,202	$162.29	$3,261,184	$89.29	$313.08
Indian River 4	NRG Power Marketing LLC	$357,065,662	$871.76	$194,115,142	$473.93	$54.04
B.L. England 2	RC Cape May Holdings, LLC	$35,953,561	$328.34	$51,779,892	$472.88	$154.51
Yorktown 1	Dominion Virginia Power	$9,739,434	$142.12	$8,427,011	$122.97	$134.64
Yorktown 2	Dominion Virginia Power	$10,045,705	$142.12	$9,529,149	$134.81	$134.64
B.L. England 3	RC Cape May Holdings, LLC	$28,710,481	$723.84	$10,058,665	$253.60	$138.95
Ashtabula	FirstEnergy Service Company	$35,236,541	$176.25	$25,177,042	$125.94	$107.91
Eastlake 1	FirstEnergy Service Company	$20,842,416	$257.01	$18,484,399	$227.93	$102.73
Eastlake 2	FirstEnergy Service Company	$20,182,025	$248.87	$17,683,994	$218.06	$102.73
Eastlake 3	FirstEnergy Service Company	$20,192,938	$249.00	$17,391,797	$214.46	$102.73
Lakeshore	FirstEnergy Service Company	$33,993,468	$240.47	$20,532,969	$145.25	$102.73
Elrama 4	GenOn Power Midwest, LP	$15,435,472	$739.88	$7,576,435	$363.17	$75.08
Niles 1	GenOn Power Midwest, LP	$9,510,580	$715.19	$4,829,423	$363.17	$75.08
Cromby 2 and Diesel	Exelon Generation Company, LLC	$20,213,406	$463.70	$17,776,658	$407.80	$108.63
Eddystone 2	Exelon Generation Company, LLC	$165,993,135	$1,467.74	$85,364,570	$754.81	$108.63
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	$60,933,986	$601.76	$23,507,795	$232.15	$89.78
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$28,934,341	$32.90	$62,364,359	$70.92	$132.72
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$47,633,115	$81.89	$79,580,435	$136.82	$97.39

In each of the cost of service recovery rate filings for Part V reliability service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover sunk costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the Part V reliability service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to develop the type of rate case filing used by regulated utilities, using a test year with adjustments, to establish a rate base including investment in the existing plant and new investment necessary to remain in service and to earn a return on that rate base and receive depreciation of that rate base, plus guarantee recovery of estimated operation and maintenance expenses without verification of actual expenses. Despite the asserted reliance on traditional cost of service ratemaking principles, in practice generators seek approval of high rates that have weak or non existent support in law and fact relative to what has been traditionally required to justify of cost of service rates. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the Part V reliability service period and have included costs incurred prior to the decision to deactivate and costs associated with closing the unit that would have been incurred regardless of the Part V reliability service period.[216] In some cases, the filing included costs that already had been written off, or impaired, on the

214 Actual cost data includes RMR charges through August 31, 2025.
215 The actual cost data for Indian River 4 include a refund of the difference between the filed rate that was collected pending resolution and the RMR settlement amount.
216 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.

company's public books.[217] [218] In another case, the filing ignored evidence of actual book value based on market purchase of the asset.[219] The cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM. The costs are generally not subject to review, audit and verification. The Commission has approved black box settlement rates (i.e., no explicit basis for the rate is stated) that included arbitrarily inflated asset values and costs, despite protests.[220]

Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service which have generally been set through settlements.

This reliability service should be provided to PJM customers at reasonable rates, which reflect the relatively low risk nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends elimination of both the cost of service recovery rate in OATT Section 119 and the deactivation avoidable cost rate in Part V, and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments.

217 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.
218 See NRG Filing, Docket No. ER22- 1539-000 (April 1, 2022).
219 See Brandon Shores, H.A. Wagner, Docket No. ER24-1787-000, et al. (April 18, 2024); Comments of the Independent Market Monitor for PJM in Opposition to Settlement, Docket No. ER24-1787-000, et al. (February 18, 2025).
220 See 190 FERC ¶ 61,026 (2025), *reh'g denied*, 191 FERC ¶ 61,170 (2025), *appeal pending* (4th Cir. Case No. 25-1561); 191 FERC ¶ 61,098 (2025), *reh'g denied*, 191 FERC ¶ 62,189 (2025).

Department of Energy (DOE) 202(c) Orders

Eddystone

On May 30, 2025, the Department of Energy (DOE) issued an order under Section 202(c) of the Federal Power Act stating that the operational availability and economic dispatch of Eddystone units 3 and 4 is necessary to meet an emergency and serve the public interest.[221] The order requires that Constellation Energy, LLC and PJM take measures to ensure that Eddystone units 3 and 4 are available to operate from May 30, 2025, through 5:03 PM EDT on August 28, 2025.[222] Eddystone Units 3 and 4 were previously scheduled to retire on May 31, 2025.

PJM and Constellation notified the Commission by letter dated June 26, 2025, that they had agreed to a rate for service under Section 202(c) based on a modified version of the Deactivation Avoidable Cost Credit method included in Section 114 of the OATT. The modified approach ensure rates based on the actual fuel costs for operating the units and a reasonable approximation of actual avoidable costs rather than the arbitrary regulated cost of service model in recent RMR cases.

On June 9, 2025, the PJM Board of Managers initiated a Critical Issue Fast Path (CIFP) stakeholder process to address the allocation of costs associated with the payments to Constellation for continuing to operate Eddystone units 3 and 4.[223] On June 26, 2025, PJM filed a cost allocation methodology related to the retention of Eddystone units 3 and 4.[224] On August 15, 2025, FERC issued an order accepting PJM's cost allocation methodology related to the retention of Eddystone units 3 and 4.[225]

On August 28, 2025, the DOE issued a subsequent order under Section 202(c) of the Federal Power Act extending the directive that Constellation Energy,

221 16 U.S.C. § 824a(c)
222 Department of Energy, Order No. 202-25-4 (May 30, 2025) <https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf>.
223 PJM. Letter from the PJM Board of Managers re CIFP <https://www.pjm.com/-/media/DotCom/committees-groups/cifp-doe-ca/postings/cifp-doe-board-letter.pdf>
224 See FERC Docket No. ER25-2653-000.
225 192 FERC ¶ 61,159 (August 15, 2025).

LLC and PJM take measures to ensure that Eddystone units 3 and 4 are available to operate from August 28, 2025, through November 26, 2025.[226]

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-34 shows the capacity factors by unit type for the first nine months of 2024 and 2025. In the first nine months of 2025, nuclear units had a capacity factor of 95.5 percent, compared to a capacity factor of 95.0 percent in the first nine months of 2024; combined cycle units had a capacity factor of 65.7 percent in the first nine months of 2025, compared to a capacity factor of 67.9 percent in the first nine months of 2024; coal units had a capacity factor of 44.8 percent in the first nine months of 2025, compared to a capacity factor of 37.5 percent in the first nine months of 2024.

226 Department of Energy, Order No. 202-25-8 (August 28, 2025) <https://www.energy.gov/sites/default/files/2025-08/202c%20Order%20No.%20202-25-8.pdf>.

Table 5-34 Capacity factor (By unit type (GWh)): January through September, 2024 and 2025[227 228 229]

	2024 (Jan-Sep)		2025 (Jan-Sep)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in Capacity Factor
Battery	38.0	1.7%	50.7	2.1%	0.4%
Combined Cycle	257,808.4	67.9%	248,924.5	65.7%	(2.2%)
Single Fuel	222,522.9	73.3%	214,761.2	70.8%	(2.5%)
Dual Fuel	35,285.5	46.6%	34,163.3	45.3%	(1.3%)
Combustion Turbine	17,984.5	9.5%	20,143.5	10.7%	1.2%
Single Fuel	11,095.9	8.4%	12,474.5	9.6%	1.1%
Dual Fuel	6,888.6	11.8%	7,669.1	13.3%	1.5%
Diesel	243.8	10.6%	285.7	12.5%	1.9%
Single Fuel	224.1	10.8%	247.9	12.0%	1.2%
Dual Fuel	19.7	8.7%	37.8	16.8%	8.1%
Diesel (Landfill gas)	685.8	47.0%	560.1	40.4%	(6.6%)
Fuel Cell	161.0	92.5%	162.6	93.8%	1.3%
Nuclear	203,815.3	95.0%	204,130.4	95.5%	0.5%
Pumped Storage Hydro	6,631.9	18.4%	6,605.9	18.4%	(0.0%)
Run of River Hydro	6,460.1	39.0%	6,044.5	36.6%	(2.4%)
Solar	13,605.6	21.0%	20,341.7	24.2%	3.2%
Steam	107,337.2	34.9%	124,230.9	41.0%	6.1%
Biomass	3,766.3	63.7%	3,801.0	65.0%	1.3%
Coal	93,487.4	37.5%	109,662.8	44.8%	7.3%
Single Fuel	93,487.4	38.2%	109,662.8	45.5%	7.3%
Dual Fuel	0.0	0.0%	0.0	0.0%	0.0%
Natural Gas	9,206.5	47.4%	9,892.5	46.6%	(0.8%)
Single Fuel	418.0	55.8%	439.5	54.4%	(1.4%)
Dual Fuel	8,788.5	28.1%	9,453.0	28.5%	0.4%
Oil	877.0	4.1%	874.6	4.5%	0.4%
Wind	21,812.4	17.5%	22,206.5	19.0%	1.6%
Total	636,584.1	49.2%	653,687.0	50.0%	0.8%

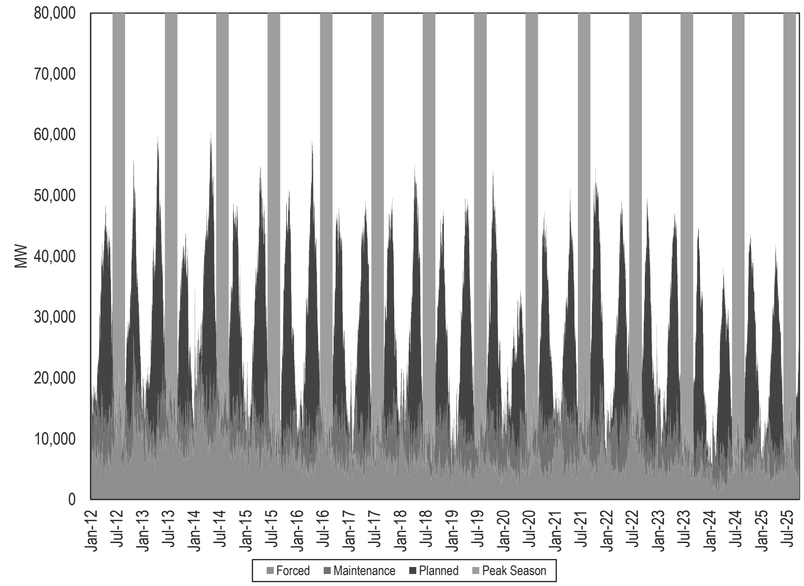
227 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
228 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
229 Hours in which batteries have net negative generation do not count toward their runtime.

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[230] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[231] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-10, as a result of restrictions on planned outages during the winter and summer. The Peak Period Maintenance Season, shown in Figure 5-10 as the peak season, runs from the weeks containing the twenty-fourth through thirty-sixth Wednesdays of the year. Planned outages cannot start in nor extend into this period. In 2025, the period runs from Monday, June 9 until Friday, September 5. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-13.

Figure 5-10 Outages (MW): 2012 through September 2025



230 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 45 (Nov. 21, 2024).
231 OATT, Attachment K (Appendix) § 1.9.3 (b).

Table 5-35 shows the total MWh by outage type. In the first nine months of 2025, forced outages were 32.6 percent higher, planned outages were 0.2 percent lower, and maintenance outages were 4.2 percent lower than in the first nine months of 2024.

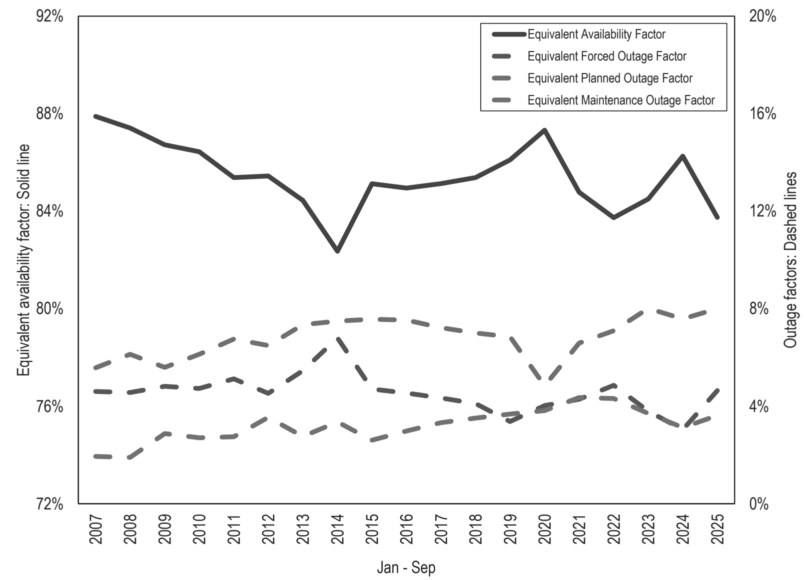
Table 5-35 Outages (MWh): January through September, 2012 through 2025

Jan-Sep	Forced MWh	Planned MWh	Maintenance MWH
2012	2,125,736	3,004,765	1,603,872
2013	2,583,519	3,375,484	1,286,707
2014	3,153,661	3,407,915	1,451,684
2015	2,216,942	3,198,529	1,162,199
2016	1,966,344	3,401,618	1,264,709
2017	1,867,831	2,977,745	1,405,039
2018	1,752,978	3,073,116	1,432,024
2019	1,511,089	2,826,875	1,493,895
2020	1,558,258	1,949,879	1,604,250
2021	1,902,931	2,519,427	1,750,786
2022	1,908,552	2,642,770	1,636,318
2023	1,467,038	2,694,613	1,314,681
2024	1,113,876	2,343,106	1,112,328
2025	1,476,870	2,338,771	1,065,814
Change in 2025 from 2024	32.6%	(0.2%)	(4.2%)

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-11. Metrics by unit type are shown in Table 5-36

Figure 5-11 Equivalent outage and availability factors: January through September, 2007 through 2025



The PJM aggregate equivalent availability factor in the first nine months of 2025 was 83.7 percent, a decrease from 86.3 percent in the first nine months of 2024.

Table 5-36 EFOF, EPOF, EMOF and EAF by unit type: January through September, 2007 through 2025

	Coal				Combined Cycle				Combustion Turbine				Diesel			
Jan-Sep	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7%	7%	3%	83%	2%	5%	2%	91%	5%	2%	2%	91%	11%	1%	2%	86%
2008	8%	7%	3%	82%	2%	5%	1%	92%	3%	4%	2%	91%	10%	1%	1%	88%
2009	7%	6%	4%	82%	4%	5%	2%	89%	1%	3%	2%	94%	7%	0%	1%	92%
2010	8%	8%	4%	79%	2%	5%	1%	91%	2%	2%	2%	95%	5%	1%	1%	94%
2011	9%	8%	4%	79%	3%	6%	1%	90%	2%	3%	1%	94%	4%	0%	2%	94%
2012	8%	8%	6%	78%	2%	6%	2%	90%	2%	2%	2%	94%	4%	0%	2%	94%
2013	9%	10%	5%	76%	1%	7%	3%	89%	6%	3%	1%	90%	6%	0%	1%	93%
2014	11%	9%	5%	75%	3%	9%	2%	87%	8%	3%	1%	87%	14%	1%	2%	83%
2015	9%	8%	4%	79%	2%	8%	2%	88%	3%	4%	2%	91%	9%	0%	2%	89%
2016	9%	8%	5%	78%	3%	8%	2%	87%	2%	5%	2%	91%	6%	0%	3%	92%
2017	10%	10%	7%	73%	2%	9%	1%	87%	1%	4%	2%	93%	6%	0%	2%	92%
2018	9%	10%	6%	74%	1%	8%	1%	89%	2%	4%	2%	93%	6%	1%	3%	90%
2019	8%	8%	7%	77%	2%	8%	2%	89%	2%	6%	1%	91%	8%	1%	2%	89%
2020	6%	6%	9%	79%	5%	5%	2%	89%	2%	3%	2%	93%	6%	0%	3%	91%
2021	8%	9%	10%	74%	3%	9%	2%	87%	2%	5%	3%	90%	8%	0%	4%	88%
2022	10%	10%	10%	70%	4%	10%	2%	85%	3%	5%	2%	90%	10%	0%	4%	85%
2023	8%	13%	7%	72%	3%	10%	2%	85%	2%	5%	2%	90%	13%	0%	3%	83%
2024	5%	10%	7%	78%	3%	10%	2%	86%	3%	5%	2%	91%	9%	1%	2%	88%
2025	8%	12%	8%	73%	5%	10%	2%	84%	4%	5%	2%	89%	13%	2%	2%	83%

	Hydroelectric				Nuclear				Other				Total			
Jan-Sep	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1%	6%	2%	92%	1%	4%	0%	95%	6%	8%	3%	84%	5%	6%	2%	88%
2008	2%	7%	2%	90%	1%	5%	1%	93%	4%	9%	3%	84%	5%	6%	2%	87%
2009	2%	9%	2%	86%	4%	4%	1%	91%	3%	8%	5%	84%	5%	6%	3%	87%
2010	1%	8%	2%	89%	2%	5%	1%	93%	4%	8%	4%	84%	5%	6%	3%	86%
2011	1%	14%	2%	83%	2%	5%	2%	91%	4%	8%	3%	84%	5%	7%	3%	85%
2012	4%	4%	2%	90%	1%	6%	1%	92%	4%	9%	4%	83%	5%	6%	4%	85%
2013	2%	7%	2%	89%	1%	5%	1%	93%	7%	10%	4%	80%	5%	7%	3%	84%
2014	2%	9%	3%	86%	2%	5%	1%	92%	7%	13%	6%	74%	7%	7%	3%	82%
2015	2%	8%	2%	88%	1%	4%	1%	93%	6%	16%	4%	73%	5%	8%	3%	85%
2016	2%	7%	3%	88%	2%	5%	1%	93%	5%	17%	4%	74%	5%	8%	3%	85%
2017	2%	6%	3%	89%	1%	5%	1%	94%	4%	9%	5%	82%	4%	7%	3%	85%
2018	2%	5%	3%	90%	1%	5%	1%	94%	4%	8%	9%	79%	4%	7%	4%	85%
2019	1%	5%	4%	90%	1%	5%	1%	94%	4%	11%	7%	78%	3%	7%	4%	86%
2020	4%	3%	3%	90%	2%	4%	1%	94%	8%	7%	5%	80%	4%	5%	4%	87%
2021	7%	3%	2%	87%	1%	4%	1%	94%	8%	6%	6%	79%	4%	7%	4%	85%
2022	3%	6%	3%	89%	1%	4%	1%	93%	6%	7%	6%	80%	5%	7%	4%	84%
2023	3%	11%	4%	81%	1%	4%	2%	94%	5%	8%	7%	80%	4%	8%	4%	84%
2024	3%	13%	3%	81%	1%	5%	2%	93%	5%	9%	3%	83%	3%	8%	3%	86%
2025	2%	9%	5%	84%	1%	5%	2%	92%	13%	10%	5%	72%	5%	8%	4%	84%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[232] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first nine months of 2025 was 6.6 percent, an increase from 4.5 percent in the first nine months of 2024. Figure 5-12 shows the average EFORd since 1999 for all units in PJM.[233]

Figure 5-12 Equivalent demand forced outage rates (EFORd): 1999 through September, 2025

Table 5-37 shows the class average EFORd by unit type.

Table 5-37 EFORd by unit type: January through September, 2007 through 2025

	Jan-Sep																		
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Coal	7.8%	9.1%	9.0%	9.9%	11.5%	10.6%	11.7%	14.2%	10.2%	10.4%	12.8%	12.1%	10.3%	9.3%	10.5%	13.9%	12.1%	7.6%	10.6%
Combined Cycle	3.7%	3.4%	4.9%	3.0%	3.2%	2.8%	1.7%	4.5%	2.5%	3.6%	2.9%	2.1%	2.0%	5.2%	3.6%	4.9%	3.9%	3.4%	6.1%
Combustion Turbine	12.0%	11.7%	8.7%	9.1%	7.4%	6.2%	10.6%	17.7%	9.5%	5.2%	4.9%	6.6%	5.3%	4.5%	5.4%	6.0%	5.5%	6.1%	7.4%
Diesel	12.6%	11.0%	9.0%	6.7%	9.8%	4.8%	6.2%	15.3%	9.8%	7.1%	7.1%	6.9%	8.0%	7.7%	10.5%	13.0%	15.5%	12.1%	15.3%
Hydroelectric	1.8%	2.6%	2.8%	1.3%	2.0%	5.2%	3.4%	3.2%	3.2%	3.0%	2.9%	2.6%	1.5%	5.1%	9.0%	3.8%	4.5%	3.4%	2.5%
Nuclear	1.3%	1.0%	4.4%	2.2%	2.6%	1.6%	1.1%	1.9%	1.2%	2.2%	0.6%	0.8%	0.7%	1.6%	0.9%	1.4%	0.5%	0.9%	0.7%
Other	10.5%	9.6%	8.6%	7.4%	8.7%	7.9%	11.6%	13.1%	12.9%	9.8%	13.0%	9.8%	10.2%	17.7%	19.4%	17.2%	6.5%	7.2%	18.0%
Total	6.6%	7.0%	7.3%	6.9%	7.6%	6.8%	7.8%	10.4%	7.1%	6.2%	6.7%	6.3%	5.4%	6.5%	6.8%	7.7%	5.6%	4.5%	6.6%

232 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable, prorated to full hours.
233 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2024 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

EFORd vs EAF

EFORd is not an adequate measure of unit availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. A unit with significant planned and/or maintenance outages is considered to have identical reliability properties in capacity planning, transmission planning and in the sale of capacity in the capacity market.[234] The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

Table 5-38 shows the differences between EFORd and EAF by unit type.

Table 5-38 EFORd and EAF by unit type: January through September, 2012 through 2025

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
Jan-Sep	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	10.6%	22.3%	2.8%	10.2%	6.2%	5.7%	4.8%	5.7%	5.2%	9.6%	1.6%	8.3%	7.9%	17.4%	6.8%	14.6%
2013	11.7%	23.5%	1.7%	11.4%	10.6%	9.9%	6.2%	7.4%	3.4%	10.7%	1.1%	6.9%	11.6%	20.3%	7.8%	15.6%
2014	14.2%	25.4%	4.5%	13.1%	17.7%	12.8%	15.3%	16.9%	3.2%	14.5%	1.9%	7.8%	13.1%	25.6%	10.4%	17.6%
2015	10.2%	20.7%	2.5%	12.3%	9.5%	8.9%	9.8%	11.4%	3.2%	12.2%	1.2%	7.0%	12.9%	26.5%	7.1%	14.9%
2016	10.4%	21.7%	3.6%	13.4%	5.2%	8.8%	7.1%	8.4%	3.0%	11.8%	2.2%	7.5%	9.8%	25.5%	6.2%	15.1%
2017	12.8%	26.5%	2.9%	12.6%	4.9%	6.9%	7.1%	8.0%	2.9%	10.6%	0.6%	5.9%	13.0%	18.1%	6.7%	14.9%
2018	12.1%	26.0%	2.1%	10.7%	6.6%	7.4%	6.9%	10.1%	2.6%	10.3%	0.8%	5.8%	9.8%	20.9%	6.3%	14.6%
2019	10.3%	22.9%	2.0%	11.2%	5.3%	8.7%	8.0%	10.9%	1.5%	9.6%	0.7%	6.3%	10.2%	21.6%	5.4%	13.9%
2020	9.3%	21.0%	5.2%	11.2%	4.5%	6.9%	7.7%	9.0%	5.1%	9.5%	1.6%	6.0%	17.7%	19.8%	6.5%	12.7%
2021	10.5%	26.3%	3.6%	13.1%	5.4%	10.2%	10.5%	12.2%	9.0%	12.8%	0.9%	6.4%	19.4%	20.8%	6.8%	15.2%
2022	13.9%	29.5%	4.9%	15.3%	6.0%	10.1%	13.0%	14.9%	3.8%	11.4%	1.4%	6.8%	17.2%	19.6%	7.7%	16.3%
2023	12.1%	27.9%	3.9%	15.4%	5.5%	9.7%	15.5%	16.7%	4.5%	18.6%	0.5%	5.8%	6.5%	19.6%	5.6%	15.5%
2024	7.6%	22.4%	3.4%	13.9%	6.1%	9.0%	12.1%	11.7%	3.4%	19.1%	0.9%	7.4%	7.2%	16.8%	4.5%	13.7%
2025	10.6%	26.9%	6.1%	16.4%	7.4%	10.8%	15.3%	17.1%	2.5%	16.0%	0.7%	7.5%	18.0%	27.9%	6.6%	16.3%
Average	11.2%	24.5%	3.5%	12.9%	7.2%	9.0%	10.0%	11.4%	3.8%	12.6%	1.2%	6.8%	12.4%	21.5%	6.7%	15.1%

234 OATT, Attachment DD (Reliability Pricing Model) § 10A (d).

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[235] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

The PJM EFOF was 4.6 percent in the first nine months of 2025. Table 5-39 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 15.1 percent of the system EFOF, were the largest single contributor to average system EFOF across all unit types.

Table 5-39 Contribution to PJM EFOF by unit type by cause: January through September, 2025

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	29.2%	3.2%	0.0%	0.0%	0.0%	0.0%	14.4%	15.1%
Boiler Air and Gas Systems	14.5%	0.1%	0.0%	0.0%	0.0%	0.0%	27.6%	11.4%
Electrical	1.6%	11.3%	32.1%	5.7%	0.8%	6.4%	0.9%	8.3%
Condensing System	1.1%	0.2%	0.0%	0.0%	0.0%	12.7%	31.3%	7.3%
Miscellaneous (Gas Turbine)	0.0%	13.0%	23.1%	0.0%	0.0%	0.0%	0.0%	6.0%
Miscellaneous (Generator)	1.6%	25.3%	0.5%	14.2%	0.3%	0.0%	0.1%	4.9%
Unit Testing	1.8%	4.0%	3.3%	13.9%	25.5%	5.7%	7.6%	4.4%
High Pressure Turbine	7.4%	3.3%	0.0%	0.0%	0.0%	0.0%	0.4%	3.6%
Auxiliary Systems	3.5%	3.4%	7.7%	0.0%	0.1%	0.0%	0.3%	3.3%
Slag and Ash Removal	6.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	2.8%
Economic	0.4%	0.2%	8.6%	2.3%	21.9%	0.0%	0.4%	2.3%
Turbine	0.0%	0.9%	8.2%	0.0%	26.3%	0.0%	0.0%	2.1%
Feedwater System	3.5%	0.4%	0.0%	0.0%	0.0%	3.3%	2.3%	2.0%
Boiler Piping System	4.5%	1.0%	0.0%	0.0%	0.0%	0.0%	0.2%	2.0%
Circulating Water Systems	3.4%	0.5%	0.0%	0.0%	0.0%	7.4%	1.1%	1.9%
Controls	2.1%	2.3%	1.2%	17.5%	0.3%	3.8%	0.6%	1.8%
Boiler Fuel Supply from Bunkers to Boiler	3.5%	0.3%	0.0%	0.0%	0.0%	0.0%	0.2%	1.5%
Fuel, Ignition and Combustion Systems	0.0%	5.6%	2.2%	0.0%	0.0%	0.0%	0.0%	1.2%
Catastrophe	0.0%	6.9%	0.4%	0.3%	3.7%	0.0%	0.0%	1.2%
All Other Causes	15.0%	18.3%	12.8%	46.2%	21.1%	60.8%	12.4%	16.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

235 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

The PJM EMOF was 3.6 percent in the first nine months of 2025. Table 5-40 shows the causes of EMOF by unit type. Maintenance outages for boiler tube leaks, 12.1 percent of the system EMOF, were the largest single contributor to average system EMOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EMOF for combustion turbines.

Table 5-40 Contribution to EMOF by unit type by cause: January through September, 2025

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	15.1%	19.8%	0.0%	0.0%	0.0%	0.0%	30.1%	12.1%
Boiler Air and Gas Systems	15.1%	0.0%	0.0%	0.0%	0.0%	0.0%	20.6%	9.8%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	70.5%	0.0%	9.4%
Miscellaneous (Balance of Plant)	12.3%	3.0%	3.2%	0.0%	0.1%	0.0%	5.8%	7.4%
Boiler Piping System	5.0%	6.9%	0.0%	0.0%	0.0%	0.0%	8.0%	3.9%
Turbine	0.0%	1.6%	1.7%	0.0%	41.2%	0.0%	0.0%	3.7%
Boiler Overhaul and Inspections	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	13.7%	3.2%
Slag and Ash Removal	6.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	3.2%
Circulating Water Systems	4.3%	8.7%	0.0%	0.0%	0.0%	0.1%	1.0%	3.0%
Generator	3.3%	0.5%	0.2%	0.0%	14.7%	0.0%	0.0%	3.0%
Wet Scrubbers	5.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%
Miscellaneous (Gas Turbine)	0.0%	6.5%	22.6%	0.0%	0.0%	0.0%	0.0%	2.6%
Boiler Tube Fireside Slagging or Fouling	4.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	2.3%
Fuel, Ignition and Combustion Systems	0.0%	11.3%	13.7%	0.0%	0.0%	0.0%	0.0%	2.2%
Electrical	0.4%	0.7%	14.7%	10.4%	3.2%	0.3%	1.6%	2.1%
Auxiliary Systems	1.8%	1.1%	10.3%	0.2%	0.5%	0.0%	0.0%	2.0%
Feedwater System	2.5%	0.7%	0.0%	0.0%	0.0%	1.5%	4.2%	1.9%
Cooling System	0.8%	0.0%	0.6%	1.9%	0.0%	7.5%	4.2%	1.9%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	13.9%	0.0%	1.8%
All Other Causes	19.3%	39.3%	33.0%	87.5%	40.2%	6.3%	10.3%	21.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 8.0 percent in the first nine months of 2025. Table 5-41 shows the causes of EPOF by unit type. Planned outages for miscellaneous balance of plant, 19.8 percent of the system EPOF, were the largest single contributor to average system EPOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EPOF for combustion turbines.

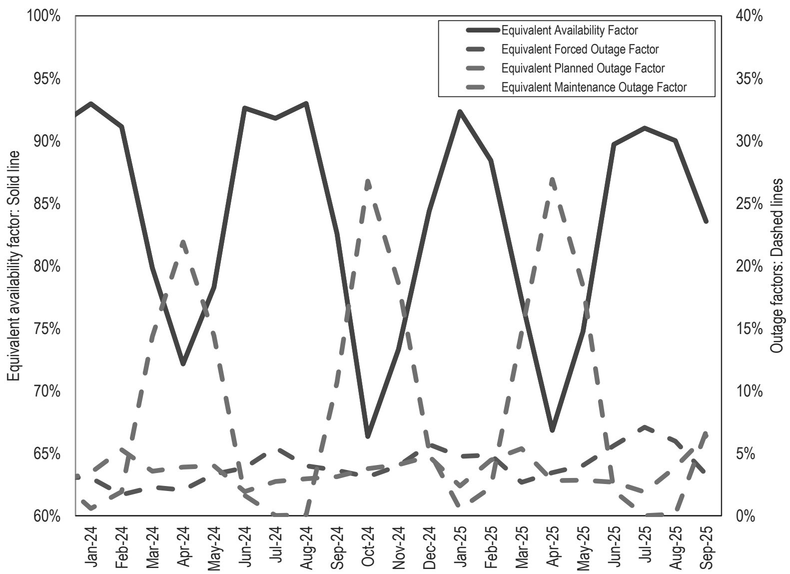
Table 5-41 Contribution to EPOF by unit type and cause: January through September, 2025

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Miscellaneous (Balance of Plant)	22.6%	32.3%	13.6%	0.1%	0.0%	0.0%	42.8%	19.8%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	98.4%	0.0%	16.8%
Miscellaneous (Gas Turbine)	0.0%	43.5%	49.6%	0.0%	0.0%	0.0%	0.0%	14.7%
Boiler Overhaul and Inspections	20.9%	1.9%	0.0%	0.0%	0.0%	0.0%	26.6%	10.0%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	94.5%	0.0%	0.0%	6.5%
Miscellaneous (Steam Turbine)	13.6%	0.6%	0.0%	0.0%	0.0%	0.0%	11.2%	5.9%
Boiler Fuel Supply from Bunkers to Boiler	12.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	4.4%
Generator	8.5%	0.0%	2.3%	0.2%	0.0%	0.0%	0.0%	3.3%
Miscellaneous (Generator)	1.4%	9.6%	2.5%	9.7%	0.0%	0.0%	0.1%	2.8%
Circulating Water Systems	2.1%	7.8%	0.0%	0.0%	0.0%	0.1%	1.7%	2.5%
Slag and Ash Removal	5.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	2.1%
Electrical	0.0%	0.0%	12.0%	4.8%	0.4%	0.0%	0.0%	1.4%
Valves	1.6%	0.6%	0.0%	0.0%	0.0%	0.0%	7.1%	1.3%
Boiler Air and Gas Systems	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	5.4%	1.1%
Continued Emissions Monitoring Systems (CEMS)	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Wet Scrubbers	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%
Auxiliary Systems	1.3%	0.6%	2.2%	0.0%	0.0%	0.0%	0.0%	0.8%
Boiler Tube Leaks	1.8%	0.6%	0.0%	0.0%	0.0%	0.0%	0.2%	0.8%
Exhaust Systems	0.0%	0.0%	5.4%	0.0%	0.0%	0.0%	0.0%	0.6%
All Other Causes	1.8%	2.6%	12.5%	85.3%	5.1%	1.6%	2.3%	3.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

Monthly values for EAF, EFOF, EMOF and EPOF are shown in Figure 5-13.

Figure 5-13 Monthly generator performance factors: January through September, 2024 through 2025



Generator Testing Issues

PJM Manual 21: Rules and Procedures for Determination of Generating Capability describes how generators are to be tested. PJM's testing requirements are not well designed, permit excessive generator discretion, and do not require adequate winter testing. As a result of the introduction of ELCC, winter capability is much more significant in defining the value of capacity that can be sold in the capacity market, especially for thermal resources. That fact makes it even more essential that PJM require winter testing and include the results of that testing in the calculation of ELCC values.

Net Capability Verification Testing data, meant to demonstrate that a unit has the ICAP claimed, are submitted for the summer and winter testing periods.[236] These periods run from the start of June until September and the start of December until March. If a unit is on a planned or maintenance outage for the entire testing period, it is expected to perform an out of period test once the outage ends. Out of period tests can be performed from the start of September until December for summer tests and from the start of March until June for winter tests. Hydroelectric generators only perform summer tests.[237] Wind and solar resources do not perform verification tests to prove capability.[238]

While data must be submitted for the winter testing period, PJM permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data. The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules and that the ambient conditions under which the tests are performed be defined.

Results, including failed test results, must be submitted to PJM via eGADS. Failing to submit data before the deadline can result in a Data Submission Charge of $500 per day late.[239]

Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test.

Failed test results must be accompanied by a derating or outage in eGADS and in eDART. Failure to report failed tests and failure to derate the unit can result in a Generation Resource Rating Test Failure Charge, equal to the Daily Deficiency Rate multiplied by: the daily ICAP shortfall multiplied by one minus the effective EFORd for unlimited resources; the UCAP for the daily ICAP shortfall, for limited duration resources and combination resources.[240] Nine resources were assessed for generation resource rating test failure charges

236 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 59 (June 27, 2024).
237 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 59 (June 27, 2024).
238 PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 59 (June 27, 2024).
239 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.
240 PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 59 (June 27, 2024).

in 2024. No resources were assessed for generation resource rating test failure charges in the first nine months of 2025.

The Daily Deficiency Rate in dollars per MW-day is equal to the weighted average capacity resource clearing price from the RPM auction that resulted in the resource's commitment plus the greater of 20 percent of that clearing price or 20 dollars per MW-day.[241]

While generation owners are required to report failed tests and to derate their unit in eGADS, owners can perform an unlimited number of tests before submitting a successful result. The MMU recommends that PJM limit the number of tests that can be made before submitting final results and that the data be collected by PJM's Power Meter instead of being submitted in eGADS. The MMU recommends that PJM select the time and day for testing a unit, not the unit owner, and that this testing not be communicated in advance. Instead, a unit would be tested by how well it follows its dispatch signal. Under the current testing rules, generation owners have the opportunity to perform tests during more favorable conditions to achieve better performance.

Generator output is also assessed during Performance Assessment Intervals (PAIs), which occur when PJM declares an emergency action as listed in Manual 18, Section 8.4A. If a unit fails to perform as expected, generators may incur a Non-Performance Charge, which is equal to the performance shortfall multiplied by the Non-Performance Charge Rate.[242] In 2022, PAIs occurred on June 13, June 14, June 15, December 23, and December 24. For the December 23 and 24 PAIs, PJM total nonperformance charges were approximately $1.796 billion, reduced to $1.226 billion in a settlement agreement.[243] There were no such charges assessed in 2023 or 2024 or the first nine months of 2025

For each day of a delivery year, generators are required to meet their daily unforced capacity commitments. Generation owners have the option to buy replacement capacity that satisfies the same locational requirements.[244] [245] Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.[246] [247] This charge is equal to the Daily Deficiency Rate multiplied by the difference between a resource's daily commitments and daily position. Thirty resources were assessed for deficiency charges in 2021, 65 resources were assessed for deficiency charges in 2022, 176 resources were assessed for deficiency charges in 2023, 432 resources were assessed for deficiency charges in 2024, and 576 resources were assessed for deficiency charges in the first nine months of 2025. The increase in the number of resources subject to deficiency charges is a result of the implementation of class average ELCC in the 2023/2024 Delivery Year and marginal ELCC starting in the 2025/2026 Delivery Year.

Changing Outage Types

Capacity resource owners have an incentive to minimize their forced outages to maximize capacity revenue and minimize penalties. Generation owners have had the ability to change the designation of the outage type after the initial submission to the eGADS database since 2014. Table 5-42 shows that from 2014 through September 2025, of all the changes in outage status, 96.2 percent of the outages and 86.5 percent of the outage MW were changed from either planned or maintenance to forced outage status. Of those changes to forced outage status, 41.3 percent of the outages and 84.1 percent of the MW were for coal and hydro plants.

241 OATT, Attachment DD (Reliability Pricing Model) § 7.
242 OATT, Attachment DD (Reliability Pricing Model) § 10A.
243 See Settlement Agreement, Docket No. ER23-2975-000 (September 29, 2023), which can be accessed at: <https://pjm.com/-/media/documents/ferc/filings/2023/20230929-er23-2975-000.ashx>.
244 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 19 (June 27, 2024).
245 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).
246 PJM. "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 59 (June 27, 2024).
247 OATT, Attachment DD (Reliability Pricing Model) § 8.

Table 5-42 Changed outages by unit type: 2014 through September 2025[248]

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Coal	2014	5	270,049	0	NA	1	2,794
	2015	0	NA	0	NA	25	876,920
	2016	1	271,304	0	NA	74	1,983,852
	2017	2	151,085	0	NA	48	1,246,484
	2018	1	1,520	0	NA	30	837,286
	2019	2	71,234	0	NA	43	618,382
	2020	1	8,587	0	NA	12	170,807
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	1	13,211	0	NA	0	NA
	2024	1	18,908	0	NA	0	NA
	2025 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	14	805,898	0	NA	233	5,736,526
Combined Cycle	2014	1	3,803	2	1,105	1	28,067
	2015	2	24,685	0	NA	3	3,330
	2016	0	NA	1	65,664	24	145,432
	2017	3	5,786	0	NA	19	400,606
	2018	1	416	0	NA	16	52,214
	2019	0	NA	0	NA	11	94,756
	2020	0	NA	0	NA	13	19,037
	2021	0	NA	7	303,061	0	NA
	2022	0	NA	1	3,817	2	208
	2023	0	NA	0	NA	0	NA
	2024	3	2,625	0	NA	0	NA
	2025 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	10	37,315	11	373,648	89	743,650
Combustion Turbine	2014	9	26,990	3	15,027	22	25,865
	2015	0	NA	0	NA	13	27,567
	2016	0	NA	0	NA	48	55,233
	2017	0	NA	0	NA	19	29,586
	2018	0	NA	2	41,737	25	24,433
	2019	0	NA	1	340	28	37,483
	2020	0	NA	0	NA	27	41,312
	2021	0	NA	0	NA	5	25,094
	2022	0	NA	0	NA	5	25,497
	2023	0	NA	0	NA	4	270,336
	2024	1	11,786	0	NA	3	173,847
	2025 (Jan-Sep)	0	NA	0	NA	2	3,195
	Total	10	38,777	6	57,104	201	739,447
Diesel	2014	0	NA	0	NA	77	4,550
	2015	15	47	0	NA	182	5,439
	2016	0	NA	0	NA	217	5,579
	2017	2	145	0	NA	175	5,883
	2018	2	15	0	NA	235	4,414
	2019	0	NA	0	NA	238	23,066
	2020	2	311	0	NA	163	6,113
	2021	3	137	0	NA	3	27,059
	2022	4	5,492	0	NA	10	305
	2023	0	NA	0	NA	0	NA
	2024	0	NA	0	NA	0	NA
	2025 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	28	6,147	0	NA	1,300	82,408

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Hydroelectric	2014	1	3	0	NA	124	1,383,319
	2015	1	162	0	NA	152	952,608
	2016	4	780	0	NA	315	1,433,851
	2017	2	52,080	0	NA	123	598,766
	2018	4	82,395	0	NA	72	405,549
	2019	0	NA	0	NA	34	148,629
	2020	0	NA	0	NA	59	281,976
	2021	0	NA	0	NA	33	263,525
	2022	0	NA	0	NA	1	4,887
	2023	0	NA	0	NA	9	196,512
	2024	0	NA	0	NA	0	NA
	2025 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	12	135,420	0	NA	922	5,669,622
Nuclear	2014	0	NA	1	177,618	0	NA
	2015	0	NA	1	573	0	NA
	2016	0	NA	0	NA	0	NA
	2017	0	NA	0	NA	0	NA
	2018	0	NA	0	NA	0	NA
	2019	0	NA	0	NA	0	NA
	2020	0	NA	0	NA	2	22,903
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	0	NA	0	NA	0	NA
	2024	0	NA	2	168,615	0	NA
	2025 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	0	NA	4	346,807	2	22,903
Other	2014	5	103,981	0	NA	1	866
	2015	0	NA	0	NA	2	176,599
	2016	1	11,680	0	NA	18	159,781
	2017	2	231	1	28,636	12	85,071
	2018	3	7,555	0	NA	1	268
	2019	1	128,664	1	8,658	9	61,297
	2020	0	NA	0	NA	4	82,250
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	2	17,023	0	NA	0	NA
	2024	0	NA	0	NA	0	NA
	2025 (Jan-Sep)	0	NA	0	NA	0	NA
	Total	14	269,134	2	37,294	47	566,132
All Units	2014	21	404,826	6	193,750	226	1,445,461
	2015	18	24,894	1	573	377	2,042,463
	2016	6	283,764	1	65,664	696	3,783,728
	2017	11	209,328	1	28,636	396	2,366,397
	2018	11	91,901	2	41,737	379	1,324,165
	2019	3	199,897	2	8,998	363	983,612
	2020	3	8,898	0	NA	280	624,398
	2021	3	137	7	303,061	41	315,679
	2022	4	5,492	1	3,817	18	30,896
	2023	3	30,234	0	NA	13	466,848
	2024	5	33,319	2	168,615	3	173,847
	2025 (Jan-Sep)	0	NA	0	NA	2	3,195
	Total	88	1,292,689	23	814,853	2794	13,560,688

248 Year describes the year in which the outage started and not the year in which the outage designation was changed.

Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation. The current PJM demand side programs do not result in a functional demand side of the electricity market.

Overview

- **Demand Response Activity.** Demand response resources include economic demand response (energy market demand resources), emergency demand response, pre-emergency demand response and price responsive demand (PRD) (capacity market demand resources), synchronized reserves and regulation.[1]

  Total demand response revenue increased by $221.8 million, 194.2 percent, from $114.2 million in the first nine months of 2024 to $336.0 million in the first nine months of 2025, primarily due to increases in capacity market revenue. Emergency demand response revenue accounted for 85.9 percent of all demand response revenue, economic demand response for 6.1 percent, demand response in the synchronized reserve market for 4.2 percent and demand response in the regulation market for 3.8 percent.

  Total emergency demand response revenue increased by $201.5 million, 231.5 percent, from $87.0 million in the first nine months of 2024 to $288.5 million in the first nine months of 2025.[2] This increase was primarily a result of higher capacity market prices and capacity market revenue.

  Economic demand response revenue increased by $11.8 million, 134.4 percent, from $8.7 million in the first nine months of 2024 to $20.5 million in the first nine months of 2025.[3] Demand response revenue in the synchronized reserve market increased by $5.9 million, 70.7 percent, from $8.3 million in the first nine months of 2024 to $14.2 million in the first nine months of 2025. Demand response revenue in the regulation market increased by $2.7 million, 26.5 percent, from $10.1 million in the first nine months of 2024 to $12.8 million in the first nine months of 2025.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments to demand response resources although emergency demand response and economic demand response can and do set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time energy market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[4]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in the first nine months of 2024 and 2025. The HHI for economic demand response resource reductions decreased by 46 points from 8846 in the first nine months of 2024 to 8800 in the first nine months of 2025.

  The ownership of emergency demand response resources is highly concentrated. The HHI for emergency demand response resources committed MW was 2387 for the 2024/2025 Delivery Year. In the 2024/2025 Delivery Year, the four largest CSPs owned 88.5 percent of all committed emergency demand response UCAP MW. The HHI for emergency demand response committed MW is 2517 for the 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, the four largest CSPs own 86.7 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. In addition, aggregation rules allow

1 Emergency demand response refers to both emergency and pre-emergency demand response.
2 The total credits and MWh numbers for demand resources were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates.
3 Economic credits are synonymous with revenue received for reductions under the economic load response program.
4 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 102 (Oct. 1, 2025).

a demand resource that incorporates many small End Use Customers to span an entire zone, which is inconsistent with nodal dispatch.

- **Energy Efficiency.** Energy efficiency payments have been eliminated from PJM markets effective June 1, 2026. Energy efficiency resources are not capacity resources in PJM and do not clear in the capacity market. The total MW of energy efficiency resources paid decreased by 80.6 percent, from 7,716.0 MW in the 2024/2025 Delivery Year to 1,493.2 MW in the 2025/2026 Delivery Year. In the 2025/2026 Delivery Year, payments to EE are $148 million.
- **Energy Efficiency Payments are a Subsidy and Uplift.** Payments from the buyers of capacity to energy efficiency providers are a subsidy and uplift. Energy efficiency is not a capacity resource and does not contribute to reliability.
- **Energy Efficiency Market Concentration.** The HHI for energy efficiency on an aggregate market basis shows that ownership is highly concentrated. The four largest companies own 90 percent or more of all paid Energy Efficiency MW. The HHI for Energy Efficiency resources also shows that ownership is highly concentrated for the 2025/2026 Delivery Year, with an HHI value of 2804. In the 2025/2026 Delivery Year, the four largest companies own 96.0 percent of all paid Energy Efficiency MW.

Recommendations

- The MMU recommends that PJM report the response of emergency demand response resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the expected response to PJM dispatch. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that emergency demand response resources offering as supply in the capacity market be required to offer a guaranteed load drop (GLD) below their PLC to ensure that demand resources provide an identifiable MW resource to PJM when called. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends, as an alternative to including emergency demand response resources as supply in the capacity market, that demand resources have the option to be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for emergency demand response resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[5] (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for emergency demand response resources and price response demand resources be the same as the maximum offer for generation resources and that the same cost verification rules applied to generation resources apply to demand resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the emergency demand response resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that emergency demand response resources not be treated as emergency resources. The MMU recommends that emergency demand response resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Partially adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market prices is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if emergency demand response resources remain in the capacity market, a daily energy market must offer requirement apply to emergency demand response resources, comparable

5 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

to the rule applicable to generation capacity resources.[6] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that emergency demand response resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of emergency demand response resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for all demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[7] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all emergency demand response resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that demand response testing be initiated by PJM with advance notice to CSPs identical to the actual lead time required in an emergency in order to accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that economic demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for emergency demand response resources clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for

6 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

7 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[8])

- The MMU recommends that all demand resources register as Pre-Emergency and that the Emergency Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that the lead times for emergency demand response resources be shortened to 30 minutes with a one hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included in the capacity market mechanism and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately. (Priority: Medium. First reported 2018. Status: Adopted 2024.)[9] [10]
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation. (Priority: Medium. First reported 2022. Status: Partially adopted.)
- The MMU recommends that the Commission require PJM to include in OATT Attachment M the explicit statement that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DERs. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level. (Priority: Medium. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that PJM revise the requirements for reporting expected real time energy load reductions by CSPs to PJM to improve the accuracy and usefulness to PJM's system operators. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI. The MMU recommends that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance. (Priority: Medium. First reported 2023. Status: Not adopted.)

8 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.
9 See 189 FERC ¶ 61,095.
10 Originally incorporated with auctions conducted in 2016 for the 2016/2017 Delivery Year and forward. The mechanics of the EE addback mechanism were modified beginning with the 2023/2024 Delivery Year.

- The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: Medium. New recommendation. Status: Not adopted.)

Conclusion

A fully functional demand side of the electricity market means that End Use Customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on how customers value the power and on the actual cost of that power.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. Demand resources do not have telemetry requirements similar to other Capacity Performance resources. Until July 30, 2023, including Winter Storm Elliott, PJM automatically, and inappropriately, triggered a PAI when demand resources were dispatched.

In order to be a substitute for generation, demand resources offering as supply in the capacity market should be required to offer a guaranteed load drop (GLD) below their PLC to ensure that demand resources provide an identifiable MW resource to PJM when called.

In order to be a substitute for generation, the ELCC for demand resources should be based on data about actual reductions in demand during high expected loss of load hours, like other capacity resources. The current DR ELCC is significantly overstated because the DR ELCC value is based on the unsupported assumption that the full amount of capacity sold will respond when called rather than on actual response data. In other words, the actual response is assumed to be perfect. The amount of capacity sold equals the PLC – the FSL for the resource. PJM has proposed to make this problem worse rather than to correct it, by increasing the ELCC of demand resources based on assumptions rather than actual performance data.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that demand resources are only obligated to respond for defined time periods meant that PJM could not fully use demand resources during Winter Storm Elliott (Elliott). Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called whenever economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. Compliance of demand resources for capacity purposes during a Performance Assessment Event is measured relative to either Peak Load Contribution or Winter Peak Load, which are static values. If a demand resource's metered load increases above these reference values during a PAI, the current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.[11]

In order to be a substitute for generation, Actual Performance of demand resources during a Performance Assessment Event should be determined consistent with that of generation and should not be netted across the Emergency Action Area (EAA). The Capacity Market Seller's Performance Shortfalls for Demand Resources in the EAA are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller's demand resources that under complied within the EAA on a prorata basis based on the under compliance MW, and such seller's demand resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller's Demand Resources that over complied within the EAA on a prorata basis based on over compliance MW, and such Market Seller's Demand Resources will be assessed Bonus Performance. Netting of performance of Demand Resources across the EAA is inconsistent with the performance measurement of other Capacity Performance resources.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As an alternative to being a substitute for generation in the capacity market, demand response resources should have the option to be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol, and PJM forecasts would immediately incorporate the impacts of demand side behavior.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[12] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[13] [14] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined

11 See PJM. MC Webinar, Market Monitor Report <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230620-webinar/item-04---imm-report.ashx> (June 20, 2023).

12 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.

13 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (March 9, 2018).

14 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (April 13, 2018).

FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance is measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[15] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours, not limited to a small number of peak hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE. But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market. That transition should be defined by the rules proposed by the MMU.

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side.[16] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP). If a demand resource location was already at a reduced load level when PJM called a PAI, the demand resource would be deemed to have performed if the PLC less the metered load level was equal to the ICAP sold in the capacity market. The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response. That is exactly what happened during Elliott. In addition, PRD is not required to respond if the LMP is less than the PRD strike price. This flawed rule meant that PRD did not fully respond during Winter Storm Elliott because PRD offered at the maximum price of $1,849 per MWh.

15 The PJM proposal from the SODRSTF weakened the proposal but was approved at the October 25, 2018 Members Committee meeting and PJM filed Tariff changes on December 7, 2018. See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

16 577 U.S. 260 (2016).

PJM Demand Response Programs

All PJM demand response programs can be grouped into economic demand response (energy market demand resources), emergency demand response, pre-emergency demand response and price responsive demand (PRD) (capacity market demand resources), synchronized reserves and regulation.[17] Table 6-1 provides an overview of the key features of PJM demand response programs.

Based on FERC Order No. 719 PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits End Use Customers' participation.[18] [19]

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Demand Response Program			Economic Demand Response Program	Price Responsive Demand
	Capacity Market Demand Response			Economic Demand Response	
Product Types	Capacity Performance, Summer-Period Capacity Performance OATT Attachment DD § 5.5A	Capacity Performance,Summer-Period Capacity Performance OATT Attachmend DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachment K § 8.1	Full Program Option (Capacity and Energy) OATT Attachemnt K § 8.1	Energy Only OATT Attachemnt K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	Non-Performance Assessment OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	Non-Performance Assessment OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	Non-Performance Assessment RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

17 Emergency demand response refers to both emergency and pre-emergency demand response.
18 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
19 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.

Non-PJM Demand Response Programs

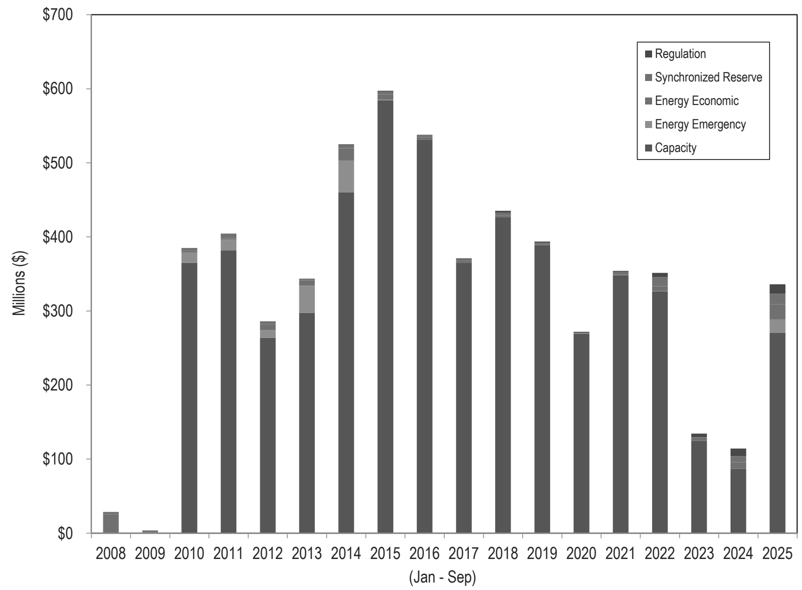
Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania (e.g. Pennsylvania ACT 129 Utility Program) and North Carolina include demand response in their RPS. If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.[20]

PJM Demand Response Programs

Figure 6-1 shows all revenue from PJM demand response programs by market for each year, 2008 through September 2025. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market has been the primary source of demand response revenue.[21] In the first nine months of 2025, total demand response revenue increased by $221.8 million, 194.2 percent, from $114.2 million in the first nine months of 2024 to $336.0 million in the first nine months of 2025, primarily due to increases in capacity market prices and revenue. Total emergency demand response revenue increased by $201.5 million, 231.5 percent, from $87.0 million in the first nine months of 2024 to $288.5 million in the first nine months of 2025. This increase was primarily a result of higher capacity market prices and capacity market revenue.[22] In the first nine months of 2025, emergency demand response revenue, which includes capacity and energy revenue, accounted for 85.9 percent of all revenue received by demand response providers, the economic program for 6.1 percent, synchronized reserve for 4.2 percent and the regulation market for 3.8 percent.

Economic demand response revenue increased by $11.8 million, 134.4 percent, from $8.7 million in the first nine months of 2024 to $20.5 million in the first nine months of 2025.[23] Demand response revenue in the synchronized reserve market increased by $5.9 million, 70.7 percent, from $8.3 million in the first nine months of 2024 to $14.2 million in the first nine months of 2025. Demand response revenue in the regulation market increased by $2.7 million, 26.5 percent, from $10.1 million in the first nine months of 2024 to $12.8 million in the first nine months of 2025.

Figure 6-1 Demand response revenue by market: January through September, 2008 to 2025



20 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.1, Rev. 136 (October 1, 2025).
21 This includes both capacity market revenue and emergency energy revenue for capacity resources.
22 The total credits and MWh for demand resources were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates.
23 Economic credits are synonymous with revenue received for reductions under the economic load response program.

Table 6-2 shows the monthly demand response cleared volumes and revenues in the synchronized reserve market.

Table 6-2 Demand response synchronized reserve market MWh and revenue: January 2024 through September 2025

	MWh			Revenue		
Month	2024	2025	Percent Change	2024	2025	Percent Change
Jan	299,469	188,234	(37.1%)	$719,294.50	$528,551.11	(26.5%)
Feb	312,394	192,247	(38.5%)	$544,082.82	$569,852.48	4.7%
Mar	340,047	339,478	(0.2%)	$1,370,683.73	$2,228,065.08	62.6%
Apr	213,888	226,206	5.8%	$877,390.11	$2,013,303.75	129.5%
May	344,696	404,918	17.5%	$1,577,366.27	$1,673,752.10	6.1%
Jun	210,675	415,556	97.2%	$606,492.40	$2,119,535.48	249.5%
Jul	218,111	393,494	80.4%	$811,495.66	$2,362,323.88	191.1%
Aug	277,126	396,407	43.0%	$776,668.66	$1,146,787.69	47.7%
Sep	302,202	393,198	30.1%	$1,059,614.05	$1,600,803.08	51.1%
Oct	287,022			$1,345,131.42		
Nov	326,015			$803,292.28		
Dec	302,315			$522,407.37		
Total (Jan-Sep)	2,518,608	2,949,738	17.1%	$8,343,088.20	$14,242,974.65	70.7%

Table 6-3 shows the monthly demand response cleared volumes and revenues in the regulation market.

Table 6-3 Demand response regulation market MWh and revenue: January 2024 through September 2025

	MWh			Revenue		
Month	2024	2025	Percent Change	2024	2025	Percent Change
Jan	35,779	36,051	0.8%	$1,423,346.65	$2,201,687.59	54.7%
Feb	35,638	33,520	(5.9%)	$793,854.86	$1,435,956.43	80.9%
Mar	36,480	36,455	(0.1%)	$955,548.18	$1,608,850.18	68.4%
Apr	34,964	34,413	(1.6%)	$829,068.59	$1,107,759.21	33.6%
May	35,437	35,331	(0.3%)	$1,386,406.04	$1,148,378.85	(17.2%)
Jun	32,568	34,489	5.9%	$909,381.10	$1,643,056.35	80.7%
Jul	35,252	30,291	(14.1%)	$1,458,331.13	$1,280,184.34	(12.2%)
Aug	35,647	31,657	(11.2%)	$1,076,920.47	$1,067,364.48	(0.9%)
Sep	35,178	29,092	(17.3%)	$1,261,594.39	$1,278,466.14	1.3%
Oct	34,748			$1,312,029.32		
Nov	36,400			$1,113,489.47		
Dec	38,657			$1,433,963.82		
Total (Jan-Sep)	316,943	301,300	(4.9%)	$10,094,451.41	$12,771,703.57	26.5%

CSPs provide for each registered location the load reduction method and the associated load reduction capability. Load reduction methods indicate the type of electrical equipment that is controlled to provide the demand response activity and include: heating, ventilation and air conditioning (HVAC), lighting, refrigeration, manufacturing, water heaters, batteries, plug load, computing and generation. A plug load represents an electronic device that is plugged into a socket, which is not already represented by the methods described above. Examples of plug load include IT peripherals such as large computers, monitors, printers, routers, copiers and scanners or appliances such as washers, dryers or dishwashers.[24]

Table 6-4 shows the demand response capability registered to provide synchronized reserves by load reduction method.

Table 6-4 Demand response synchronized reserve load reduction methods: January through September, 2025

Method	MW	Percent
Generator	139.1	5.7%
HVAC	78.9	3.2%
Lighting	165.3	6.8%
Refrigeration	16.0	0.7%
Manufacturing	1,362.0	55.7%
Water Heaters	0.0	0.0%
Batteries	14.1	0.6%
Plug Load	1.6	0.1%
Computing	670.3	27.4%
Total	2,447.2	100.0%

Table 6-5 shows the demand response capability registered to provide regulation by load reduction method.

Table 6-5 Demand response regulation load reduction methods: January through September, 2025

Method	MW	Percent
Water Heaters	143.8	63.1%
Batteries	84.2	36.9%
Total	228.0	100.0%

24 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.2.2, Rev. 136 (October 1, 2025).

Emergency and Pre-Emergency Demand Response Programs

Pre-Emergency is the default status for capacity market demand response resources. Emergency status is only for resources that use behind the meter generation and that generation has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[25] All demand resources must register as pre-emergency unless the participant qualifies for emergency. PJM also uses the term Load Management Program to refer to the emergency and pre-emergency demand response resources.

Capacity demand response resources may be dispatched both as part of, and absent, a PAI. While demand resources dispatched during a PAI continue to be subject to Non-Performance Assessment charges, demand resources dispatched outside of a PAI are not subject to any event specific penalties.[26] If a demand resource is dispatched only outside of Performance Assessment Events for the delivery year, its performance for the delivery year is determined based on the better of actual performance or a test.[27] There are no penalties or consequences for demand response nonperformance.

For example, if a demand resource is called upon five times during the delivery year only outside of Performance Assessment events and fails to perform each time, its delivery year performance will be based only on a test. If the performance under the test is better than the actual performance, no penalties would be levied even though the resource failed to perform each time it was needed.

The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI. The MMU recommends that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance.

25 OA Schedule 1 § 8.5.
26 "PJM Manual 18: PJM Capacity Market," § 8.6, Rev. 61 (July 23, 2025).
27 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 61 (July 23, 2025). Load Management Test.

In all demand response programs, CSPs are companies that sign up end use retail customers that have the ability to reduce load. CSPs satisfy cleared RPM commitments by registering end use retail customers as Nominated MW.[28] After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

All emergency or pre-emergency demand resources must be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement.[29]

The rules applied to demand resources (DR) in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI unless the product type and lead time type are dispatched by PJM. PJM does not dispatch DR nodally like other capacity resources. DR can only be dispatched on a zonal or subzonal basis. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI if the area dispatched is not a defined subzone or control zone. With the dispatch of DR no longer triggering a PAI, demand resources dispatched outside of a PAI are no longer subject to any event specific penalties or consequences for nonperformance.

Demand resources are not subject to the same rules as other capacity resources related to the definition of response. Increases in load are ignored when calculating the response of DR to a PJM dispatch.

28 See RAA Schedule 6. Since 2010, the PJM tariff definition of "End User Customer" limits the scope of the term to mean only PJM Members. Letter Order, Docket No. ER11-1909-000 (December 20, 2010). Recently, PJM has asserted that the reference in RAA Schedule 6 § L.1 and OATT Attachment DD-1 § L.1 to the defined term, "End Use Customer," was a mistake, and proposed to discontinue use of the defined term in the February 8, 2024, meeting of the PJM Governing Document Enhancement and Clarification Subcommittee (GDECS). The proposed change would remove the current requirement in the filed tariff that End Use Customers be PJM Members. The proposed change is substantive and not a correction of a typographical error.
29 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM EPT. *See* PJM OATT RAA Article 1.

Demand resources are not required to meet the same must offer requirements as other capacity resources. All other capacity resources must offer in the capacity market and all other capacity resources must offer their ICAP MW daily in the day-ahead energy market.

The MMU has made recommendations that would provide a capacity market supply side and a demand side option and that would result in treating demand resources in a manner comparable to other capacity and energy resources and in a way that would ensure that the demand side contribution to reliability is accurately measured.

Market Structure

The HHI for demand resources shows that ownership was highly concentrated for the 2024/2025 Delivery Year, with an HHI value of 2387. In the 2024/2025 Delivery Year, the four largest companies contributed 88.5 percent of all committed demand response UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2025/2026 Delivery Year, with an HHI value of 2517. In the 2025/2026 Delivery Year, the four largest companies own 86.7 percent of all committed demand response UCAP MW.

Table 6-6 shows the HHI value for committed Demand Response UCAP MW and the market share of the four largest suppliers by delivery year.

Table 6-6 Demand Response HHI: 2019/2020 through 2025/2026

Delivery Year	HHI	Structure	Top 4 Market Share
2019/2020	1840	Highly Concentrated	79.1%
2020/2021	2523	Highly Concentrated	88.4%
2021/2022	2070	Highly Concentrated	85.3%
2022/2023	2051	Highly Concentrated	82.8%
2023/2024	2295	Highly Concentrated	85.6%
2024/2025	2387	Highly Concentrated	88.5%
2025/2026	2517	Highly Concentrated	86.7%

Table 6-7 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

Table 6-7 HHI value for committed UCAP MW by LDA by delivery year: 2024/2025 and 2025/2026 Delivery Years[30]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2024/2025	ATSI	541.0	2839	High
	ATSI-CLEVELAND	141.6	3081	High
	BGE	198.1	3006	High
	COMED	1,554.0	2993	High
	DAY	192.9	3696	High
	DEOK	221.9	3157	High
	DPL-SOUTH	46.0	3515	High
	EMAAC	672.3	2802	High
	MAAC	531.7	2154	High
	PEPCO	160.4	2545	High
	PPL	603.4	2355	High
	PS-NORTH	98.2	2336	High
	PSEG	187.5	2289	High
	RTO	2,915.7	2258	High
2025/2026	ATSI	615.4	2255	High
	ATSI-CLEVELAND	97.3	3262	High
	BGE	168.3	3679	High
	COMED	1,090.5	3119	High
	DAY	141.0	3899	High
	DEOK	159.6	4581	High
	DOM	673.5	3003	High
	DPL-SOUTH	65.0	3876	High
	EMAAC	491.0	3156	High
	MAAC	347.0	2747	High
	PEPCO	135.7	2568	High
	PPL	424.9	2513	High
	PS-NORTH	65.8	2613	High
	PSEG	163.1	2615	High
	RTO	1,627.8	2282	High

Market Performance

Table 6-8 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM decreased by 1,798.8 MW, or 22.3 percent, from 8,064.7 MW in the 2024/2025 Delivery Year to 6,265.9 MW in the 2025/2026 Delivery Year. The DR percent of capacity decreased by 0.7 percentage points, from 5.2 percent in the 2024/2025 Delivery Year to 4.5 percent in the 2025/2026 Delivery Year.

30 The RTO LDA refers to the rest of RTO.

Table 6-8 Cleared Demand Resource UCAP MW: 2007/2008 through 2025/2026 Delivery Year

	UCAP (MW)		
	DR RPM Cleared	Total RPM Cleared	DR Percent Cleared
2007/2008	127.6	129,409.2	0.1%
2008/2009	559.4	130,629.8	0.4%
2009/2010	892.9	134,030.2	0.7%
2010/2011	962.9	134,036.2	0.7%
2011/2012	1,826.6	134,182.6	1.4%
2012/2013	8,740.9	141,295.6	6.2%
2013/2014	10,779.6	159,844.5	6.7%
2014/2015	14,943.0	161,214.4	9.3%
2015/2016	15,453.7	173,845.5	8.9%
2016/2017	13,265.3	179,773.6	7.4%
2017/2018	11,870.5	180,590.5	6.6%
2018/2019	11,435.4	175,996.0	6.5%
2019/2020	10,703.1	177,064.2	6.0%
2020/2021	9,445.7	174,023.8	5.4%
2021/2022	11,427.7	174,713.0	6.5%
2022/2023	8,866.2	150,465.2	5.9%
2023/2024	8,174.1	150,143.9	5.4%
2024/2025	8,064.7	154,362.5	5.2%
2025/2026	6,265.9	137,733.6	4.5%

Table 6-9 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2025. Capacity market revenue increased in the first nine months of 2025 by $183.6 million, 211.0 percent, from $87.0 million in the first nine months of 2024 to $270.6 million in the first nine months of 2025. The increase in capacity market revenue was a result of the increase in capacity market clearing prices between the 2024/2025 and 2025/2026 Delivery Years. The RTO clearing price in the 2024/2025 BRA was $28.92/MW-Day compared to $269.92/MW-Day in the 2025/2026 BRA.

Table 6-9 Zonal monthly demand resource capacity revenue: January through September, 2025

Zone	January	February	March	April	May	June	July	August	September	Total
ACEC	$110,995	$100,253	$110,995	$107,414	$110,995	$331,192	$342,232	$342,232	$331,192	$1,887,501
AEP, EKPC	$1,240,632	$1,120,571	$1,240,632	$1,200,612	$1,240,632	$8,449,197	$8,730,837	$8,730,837	$8,449,197	$40,403,148
APS	$573,335	$517,851	$573,335	$554,841	$573,335	$3,970,252	$4,102,594	$4,102,594	$3,970,252	$18,938,390
ATSI	$619,177	$559,256	$619,177	$599,203	$619,177	$6,040,952	$6,242,317	$6,242,317	$6,040,952	$27,582,527
BGE	$448,300	$404,916	$448,300	$433,839	$448,300	$2,368,036	$2,446,970	$2,446,970	$2,368,036	$11,813,668
COMED	$1,264,960	$1,142,544	$1,264,960	$1,224,155	$1,264,960	$8,002,210	$8,268,950	$8,268,950	$8,002,210	$38,703,898
DAY	$174,561	$157,668	$174,561	$168,930	$174,561	$1,143,220	$1,181,327	$1,181,327	$1,143,220	$5,499,376
DOM	$726,698	$656,372	$726,698	$703,256	$726,698	$8,976,273	$9,275,482	$9,275,482	$8,976,273	$40,043,232
DPL	$783,183	$707,391	$783,183	$757,919	$783,183	$949,849	$981,511	$981,511	$949,849	$7,677,580
DUKE	$662,025	$597,958	$662,025	$640,670	$662,025	$1,292,377	$1,335,456	$1,335,456	$1,292,377	$8,480,372
DUQ	$108,120	$97,657	$108,120	$104,632	$108,120	$714,370	$738,183	$738,183	$714,370	$3,431,754
JCPLC	$218,999	$197,805	$218,999	$211,934	$218,999	$815,429	$842,610	$842,610	$815,429	$4,382,814
MEC	$334,147	$301,810	$334,147	$323,368	$334,147	$1,101,274	$1,137,983	$1,137,983	$1,101,274	$6,106,131
PE	$481,583	$434,978	$481,583	$466,048	$481,583	$1,713,128	$1,770,232	$1,770,232	$1,713,128	$9,312,494
PECO	$607,149	$548,392	$607,149	$587,563	$607,149	$2,390,735	$2,470,426	$2,470,426	$2,390,735	$12,679,723
PEPCO	$224,452	$202,731	$224,452	$217,212	$224,452	$1,019,002	$1,052,969	$1,052,969	$1,019,002	$5,237,240
PPL	$925,730	$836,143	$925,730	$895,868	$925,730	$3,444,557	$3,559,375	$3,559,375	$3,444,557	$18,517,066
PSEG	$474,719	$428,779	$474,719	$459,406	$474,719	$1,853,541	$1,915,325	$1,915,325	$1,853,541	$9,850,074
REC	$4,486	$4,052	$4,486	$4,342	$4,486	$18,625	$19,245	$19,245	$18,625	$97,593
TOTAL	$9,983,251	$9,017,130	$9,983,251	$9,661,211	$9,983,251	$54,594,218	$56,414,025	$56,414,025	$54,594,218	$270,644,579

Product Definition

Pre-Emergency and Emergency Load Response resources must register all resources with a specific response time. The options are to respond within 30, 60 or 120 minutes of a PJM dispatched event. The 30 minute prior notification is the default and applies unless a CSP obtains an exception from PJM due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe.

Table 6-10 shows the amount of nominated MW and locations by product type and lead time for the 2024/2025 Delivery Year. Nominated MW are Pre-Emergency or Emergency Load Response registrations used to satisfy a CSP's committed MW position for a delivery year. PJM approved 2,681 locations, or 16.1 percent of all locations, which have 3,287.5 nominated MW, or 45.6 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2024/2025 Delivery Year.

Table 6-10 Nominated MW and locations by product type and lead time: 2024/2025 Delivery Year

	Pre-Emergency		Emergency			
Lead Type	MW	Percent	MW	Percent	Total	Percent of Total
30 Minutes	3,797.5	96.7%	130.4	3.3%	3,927.9	54.4%
60 Minutes	264.3	89.4%	31.2	10.6%	295.5	4.1%
120 Minutes	2,908.9	97.2%	83.2	2.8%	2,992.0	41.5%
Total	6,970.7	96.6%	244.8	3.4%	7,215.5	100.0%

	Pre-Emergency		Emergency			
Lead Type	Locations	Percent	Locations	Percent	Total	Percent of Total
30 Minutes	13,775	98.8%	165	1.2%	13,940	83.9%
60 Minutes	330	96.5%	12	3.5%	342	2.1%
120 Minutes	2,293	98.0%	46	2.0%	2,339	14.1%
Total	16,398	98.7%	223	1.3%	16,621	100.0%

Table 6-11 shows the amount of nominated MW and locations by product type and lead time for the 2025/2026 Delivery Year. PJM approved 4,926 locations, or 23.4 percent of all locations, which have 4,357.8 nominated MW, or 54.5 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2025/2026 Delivery Year.

Table 6-11 Nominated MW and locations by product type and lead time: 2025/2026 Delivery Year

	Pre-Emergency		Emergency			
Lead Type	MW	Percent	MW	Percent	Total	Percent of Total
30 Minutes	3,528.5	96.9%	113.3	3.1%	3,641.8	45.5%
60 Minutes	462.0	92.6%	37.0	7.4%	499.1	6.2%
120 Minutes	3,755.5	97.3%	103.2	2.7%	3,858.8	48.2%
Total	7,746.1	96.8%	253.5	3.2%	7,999.6	100.0%

	Pre-Emergency		Emergency			
Lead Type	Locations	Percent	Locations	Percent	Total	Percent of Total
30 Minutes	15,989	99.1%	141	0.9%	16,130	76.6%
60 Minutes	435	97.1%	13	2.9%	448	2.1%
120 Minutes	4,436	99.1%	42	0.9%	4,478	21.3%
Total	20,860	99.1%	196	0.9%	21,056	100.0%

The alternative notification times are 60 minutes and 120 minutes. The CSP must request an exception in writing, including the reason(s) for the requested exception. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year.

The request for an exception must demonstrate one of four defined reasons:[31]

- The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;
- Transfer of load to backup generation requires time intensive manual process taking more than 30 minutes;
- Onsite safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,
- The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within 30 minutes due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

Table 6-12 shows the nominated MW and locations by product type and lead time of granted lead time exceptions for the 2025/2026 Delivery Year.[32]

Table 6-12 Nominated MW and locations of granted lead time exceptions: 2025/2026 Delivery Year

	60 Minutes		120 Minutes			
Reason	MW	Percent	MW	Percent	Total	Percent
Generation Start Time	50.4	1.2%	475.2	10.9%	525.6	12.1%
Manufacturing Damage	208.6	4.8%	2,257.4	51.8%	2,466.1	56.6%
Safety Problem	240.0	5.5%	1,126.2	25.8%	1,366.3	31.4%
Total	499.1	11.5%	3,858.8	88.5%	4,357.8	100.0%

	60 Minutes		120 Minutes			
Reason	Locations	Percent	Locations	Percent	Total	Percent
Generation Start Time	24	0.5%	1,491	30.3%	1,515	30.8%
Manufacturing Damage	250	5.1%	1,096	22.2%	1,346	27.3%
Safety Problem	174	3.5%	1,891	38.4%	2,065	41.9%
Total	448	9.1%	4,478	90.9%	4,926	100.0%

Prior to participating in the PJM Markets, CSPs must complete a registration in DR Hub which identifies the specific location(s) based on the unique EDC

31 OATT Attachment DD-1, Section A.2(a).
32 Data for generation start time and mass market communication categories were combined based on confidentiality rules.

account number that will participate and their associated load reduction capability. Locations are identified by zone, street address and zip code and are not nodal. CSPs must maintain the accuracy of the registration information provided to PJM for each demand resource and each time the CSP registers the location or extends the registration, the CSP must review all information to ensure it is accurate and update as necessary. In order to register demand resources, the CSPs must classify locations according to the location's primary purpose or business use. CSPs first determine if the location's business use falls under one of the following primary categories: Hospitals, Industrial / Manufacturing, Multiple Dwelling Unit, Office Building, Residential, Retail Service, Correctional Facilities, Data Center, Data Center with Crypto Mining, or Schools. In cases where the location does not fit into one of the primary categories, the CSP selects from one of the following categories: Agriculture, Forestry and Fishing, Mining, Transportation, Communications, Electric, Gas and Sanitary Services or Services.[33] PJM had previously not been explicitly identifying demand response associated with data center load in the registration process. PJM was instead including nominated capacity and load reductions from data centers with crypto mining as a load reduction method under the plug load category. At the April 23, 2025, Markets and Reliability Committee, PJM members endorsed changes to Manual 11 to discontinue this practice. The adopted changes relocated the reference to data centers in the registration process from the load reduction method/plug load section to the business segment section and separately identifies data centers and data centers with crypto mining.[34]

Table 6-13 shows the nominated MW and locations by business segment for the 2025/2026 Delivery Year.

33 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.2.2, Rev. 136 (October 1, 2025).
34 See PJM, Consent Agenda B – 1 Manual 11 Revisions - Presentation, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250423/20250423-consent-agenda-b---1--manual-11-revisions---presentation.pdf> (April 23, 2025).

Table 6-13 Nominated MW and locations by business segment: 2025/2026 Delivery Year

Business Segment	Nominated MW (ICAP)	Percent of Total	Locations	Percent of Total
Industrial/Manufacturing	3,882.2	48.5%	3,490	16.6%
Schools	795.2	9.9%	4,028	19.1%
Transportation, Communications, Electric, Gas and Sanitary Services	534.1	6.7%	517	2.5%
Office Building	485.8	6.1%	1,271	6.0%
Services	477.3	6.0%	762	3.6%
Hospitals	421.5	5.3%	365	1.7%
Retail Service	322.9	4.0%	6,753	32.1%
Mining	284.4	3.6%	156	0.7%
Data Center	281.0	3.5%	53	0.3%
Residential	200.3	2.5%	3,113	14.8%
Agriculture, Forestry and Fishing	126.3	1.6%	273	1.3%
Data Center with Crypto Mining	115.2	1.4%	29	0.1%
Multiple Dwelling Unit	37.6	0.5%	206	1.0%
Correctional Facilities	35.7	0.4%	40	0.2%
Total	7,999.6	100.0%	21,056	100.0%

There are two ways to measure the load reductions of emergency demand response resources. The Firm Service Level (FSL) method for the summer period, measures the difference between a customer's peak load contribution (PLC) and its real-time load, multiplied by the loss factor (LF) to account for transmission and distribution line losses.[35] The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[36]

With the introduction of the Winter Peak Load (WPL) concept, effective for the 2017/2018 Delivery Year, both the FSL and GLD methods are modified for the non-summer period. The FSL method measures compliance during the non-summer period as the difference between a customer's WPL multiplied by the

35 Real-time load is hourly metered load.
36 See 135 FERC ¶ 61,212 (2011).

Zonal Winter Weather Adjustment Factor (ZWWAF) and the loss factor (LF), rather than the PLC, and real-time load, multiplied by the LF. PJM calculates and posts on the PJM website the ZWWAF as the zonal winter weather normalized peak divided by the zonal average of the five coincident peak loads in December through February.[37] The Winter Peak Load is determined based on the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined five coincident peak days from December through February two delivery years prior to the delivery year for which the registration is submitted. The Winter Peak Load is adjusted up for transmission and distribution line loss factors (LF) because one MW of load would be served by more than one MW of generation to account for transmission losses. The Winter Peak Load is normalized based on the winter conditions during the five coincident peak loads in winter using the ZWWAF to account for an extreme temperatures or a mild winter. The GLD method measures compliance during the non-summer period as the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the WPL multiplied by the ZWWAF and the LF, rather than the PLC, minus the real-time load multiplied by the LF.[38]

The capacity market is an annual market. A Capacity Performance resource has an annual commitment. Effective with the 2020/2021 Delivery Year, the capacity market design also includes the ability to offer Seasonal Capacity Performance Resources directly into the RPM Auction as an alternative to entering into a commercial arrangement to establish and offer an Aggregate Resource.[39]Capacity Market Sellers may submit sell offers of either Summer Period Capacity Performance Resources or Winter Period Capacity Performance Resources and the auction clearing optimization algorithm is designed to clear equal quantities of offsetting seasonal capacity sell offers thereby creating an annual capacity commitment by matching a Summer Period Capacity Performance Resource with a Winter Period Capacity Performance Resource. Load is allocated capacity obligations based on the annual peak load which is a summer load. The amount of capacity MW allocated to load does not vary based on winter demand. The principle is that a customer's actual use of capacity should be compared to the level of capacity that a customer is required to pay for. Capacity costs are allocated to LSEs by PJM based on the single coincident peak load method. In PJM, the single coincident peak occurs in the summer.[40] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[41] The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. If an end customer has 3 MW of load during the coincident peak load hour, but only 1 MW during the coincident winter peak load hour, the End Use Customer must pay for 3 MW of capacity for the entire delivery year, but can only participate as a 1 MW demand response resource. Using PLC to measure compliance for the entire delivery year would allow the customer to fully participate as a 3 MW demand response resource. FERC allowed the use of the WPL for calculating compliance for non-summer months effective June 1, 2017.[42] The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

37 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 61 (July 23, 2025).
38 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 61 (July 23, 2025).
39 An Aggregate Resource is created by a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources or Environmentally Limited Resources by submitting a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer is considered to be located in the smallest modeled LDA common to the aggregated resources.
40 OATT Attachment DD § 5.11.
41 OATT Attachment M-2.
42 162 FERC ¶ 61,159 (2018).

For Demand Resources prior to the 2025/2026 Delivery Year, PJM calculated UCAP as the product of the FPR and the Demand Resource's Nominated Value, which depends on the peak load contribution of customers on the Demand Resource registration and their committed Firm Service Level or Guaranteed Load Drop.[43]

Similarly, the UCAP of an Energy Efficiency Resource is the product of the FPR and the resource's Nominated Energy Efficiency Value, which is the resource's expected average load reduction during the EE Performance Hours defined in the RAA.[44] The current accreditation practice for Demand Resources and Energy Efficiency Resources assumes they provide 100 percent performance at any time they are required to perform. Beginning with the 2025/2026 Delivery Year, PJM instituted an ELCC approach for generation and emergency demand response resources. This accreditation change does not apply to Energy Efficiency Resources whose UCAP value continues to be determined using FPR. For Demand Resources, PJM calculates Accredited UCAP as the product of the resource's Nominated Value and its ELCC Class Rating. Unlike generation, PJM does not apply a resource specific performance adjustment for Demand Resources. The Demand Resource availability window, defined in the RAA for Annual Demand Resources and Summer-Period Demand Resources, does not align with the projected hours with a loss of load risk in the winter period.[45] The ELCC class rating for Demand Resources for the 2025/2026 BRA is 76 percent.[46]

PJM makes several unsupported assumptions when calculating ELCC for demand response resources. The PJM ELCC calculations do not account for the actual historical performance of DR in same way as thermal resources. PJM analysis showed that the ELCC reduction capability is overstated compared to the metered DR reduction capability.[47] This overstatement of performance is consistent with the observed performance of DR during Winter Storm Elliott. There was a significant disparity between the reported expected reduction capability provided by the CSPs and the actual observed energy reduction during Winter Storm Elliott. As a general matter, these resources are rarely used.

Beginning in May 2024 the MIC worked on a problem statement and issue charge regarding the alignment of demand response capacity availability hours with periods of reliability risk.[48] PJM proposed to expand the window to all hours. PJM also proposed to use coincident peak demand rather than the sum of noncoincident peak demands to measure the level of demand resources. The MMU supported the extension of availability to all hours, consistent with all other capacity resources. The MMU supported the proposal to measure all DR for the same coincident peak demand hour as a more accurate measure of the level of actual DR potential rather than the overstatement that has resulted from adding together all the DR from individual non coincident peak hours.

PJM also proposed to increase the ELCC derating factor from 76 percent to 94 percent, an increase of 24 percent in the value of demand resource MW. PJM's proposed ELCC value for DR is not consistent with the method PJM uses for generation resources. PJM's proposed ELCC for DR is based on assumed behavior and not based on the actual performance of demand resources during the same high EUE (expected unserved energy) hours used for other capacity resources. The current ELCC value for demand response is already overstated. As currently demand resources are inferior resources in the capacity market and the ELCC values, both existing and proposed, significantly overstate their contribution to reliability. The demand resources are rarely used. While PJM may call on demand resources as part of its emergency actions, there are no PJM rules governing the overall commitment and dispatch of demand resources as there are for all other capacity resources.[49] Demand resources do not have a must offer obligation in the energy market as all other capacity resources do. PJM rules do not indicate if, when and how demand resources should be called on for nonemergency events. PJM rules do not require the use of demand resources under defined conditions. PJM rules do not require that demand resources be called on during emergency events but leave all emergency actions to the discretion of PJM dispatchers. The proposed changes

43 See PJM, Intra-PJM Tariffs, RAA, Schedule 6 (18.0.0), § 6.I.
44 See PJM, Intra-PJM Tariffs, RAA, Schedule 6 (18.0.0), § 6.L.2.
45 See "Responses to Deficiency Letter – Capacity Market Reforms to Accommodate the Energy Transition," ER24-99-001. (December 1, 2023), at p 28.
46 See "*2025-2026 BRA ELCC Class Ratings*," <https://pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx> (March 13, 2024).
47 See PJM, DR Availability Window: Additional DR ELCC Information, <https://pjm.com/-/media/committees-groups/committees/mic/2024/20240807/20240807-item-08b---pjm-dr-education.ashx> (August 7, 2024).
48 See *Approved Minutes from the Markets & Reliability Committee*, <https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240627/20240627-consent-agenda-a---draft-mrc-minutes---05222024.ashx>.
49 See PJM Manual 13: Emergency Operations, §2.3.2. Rev. 96 (Sept. 25, 2025).

would increase the value of demand resources by almost a billion dollars ($880.7M) without any actual change in the physical reality and without the type of detailed analysis applied to other capacity resources.[50] The proposed changes would simply pay demand response more for capacity without any increase in use and without any rules governing when demand response can or will be used for economic reasons and without a must offer obligation in the energy or capacity markets, and without any market power mitigation rules, without resource specific performance adjustments, and without addressing the fact that demand side performance metrics simply ignore increases in load above the WPL when called. PJM did not propose consistent changes to the treatment of demand resources in the summer. PJM proposed to make these changes to the ELCC value of demand response resources while ignoring significant issues with the treatment of other resource technologies. The result of this administrative change would also be to affect the ELCC of other classes and to make it appear that PJM is more reliable than it is. PJM filed these proposed changes on March 6, 2025, in Docket No. ER25-1525-000.[51] The MMU filed an answer and motion for leave to answer on April 14, 2025.[52] On May 5, 2025, in Docket No. ER25-1525-000, FERC accepted PJM's section 205 proposal to revise the RAA, effective with the 2027/2028 Delivery Year, that extends the Demand Resource availability window to 24 hours a day throughout the year and revises the definition of Winter Peak Load used in calculating Demand Resources' Winter Nominated Value in PJM's ELCC method, effective May 6, 2025.[53]

Table 6-14 shows the MW registered by measurement and verification method and by technology type for the 2025/2026 Delivery Year. For the 2025/2026 Delivery Year, 99.75 percent of the MW use the FSL method and 0.25 percent of the MW use the GLD measurement and verification method.

50 See PJM, DR Availability Window – IMM Proposal, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250205/20250205-item-02-2---dr-availability-window---imm-proposal.pdf> (February 5, 2025).
51 See "Proposal to Extend Demand Resource Availability Window and Revise Calculation of Demand Resource Winter Nominated Value," Docket No. ER25-1525-000 (March 6, 2025).
52 See "Answer and Motion for Leave to Answer," Docket No. ER25-1525-000 (April 14, 2025).
53 191 FERC ¶ 61,103

Table 6-14 Nominated MW by each demand response method: 2025/2026 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,258.3	1,892.9	210.8	792.0	3,659.3	24.4	141.6	7,979.3	99.75%
Guaranteed Load Drop	5.1	1.1	0.0	0.0	14.1	0.0	0.0	20.3	0.25%
Total	1,263.4	1,894.0	210.8	792.0	3,673.4	24.4	141.6	7,999.6	100.0%
Percent by method	15.8%	23.7%	2.6%	9.9%	45.9%	0.3%	1.8%	100.0%	

Table 6-15 shows the fuel type used in the onsite generators for the 2025/2026 Delivery Year in the emergency and pre-emergency programs. For the 2025/2026 Delivery Year, 1,263.4 MW of the 7,999.6 nominated MW, 15.8 percent, used onsite generation. Of the 1,263.4 MW, 84.5 percent used diesel and 15.5 percent used natural gas, gasoline, oil, propane or waste products. Some DR registrations reflect a participant's reliance on behind the meter generation having environmental restrictions that limit the resource's ability to operate only in emergency conditions. Demand resources relying on behind the meter generation having environmental restrictions limiting the resource's ability to operate only in emergency conditions must register as emergency DR. EPA regulations require that Reciprocating Internal Combustion Engines (RICE) that do not meet EPA emissions standards (stationary emergency RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations. PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. PJM's DR Hub does not explicitly identify Reciprocating Internal Combustion Engines (RICE) generators, only whether it is an internal combustion engine. For the 2025/2026 Delivery Year, of the 253.5 MW registered as generation backed emergency DR, 251.4 MW, or 19.9 percent of all onsite generation, are backed by internal combustion engines. Stationary emergency RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

Table 6-15 Onsite generation fuel type (MW): 2025/2026 Delivery Year

	2025/2026	
Fuel Type	MW	Percent
Diesel	1,068.1	84.5%
Natural Gas, Gasoline, Oil, Propane, Waste Products	195.3	15.5%
Total	1,263.4	100.0%

Table 6-16 shows the MW registered by measurement and verification method and by technology type for the 2024/2025 Delivery Year. For the 2024/2025 Delivery Year, 99.99 percent use the FSL method and 0.01 percent use the GLD measurement and verification method.

Table 6-16 Nominated MW by each demand response method: 2024/2025 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,050.5	1,731.0	192.5	663.3	3,438.5	22.3	116.5	7,214.7	99.99%
Guaranteed Load Drop	0.0	0.7	0.0	0.0	0.1	0.0	0.0	0.8	0.01%
Total	1,050.5	1,731.7	192.5	663.3	3,438.6	22.3	116.5	7,215.5	100.0%
Percent by method	14.6%	24.0%	2.7%	9.2%	47.7%	0.3%	1.6%	100.0%	

Table 6-17 shows the fuel type used in the onsite generators for the 2024/2025 Delivery Year in the emergency and pre-emergency programs. For the 2024/2025 Delivery Year, 1,050.5 MW of the 7,215.5 nominated MW, 14.6 percent, use onsite generation. Of the 1,050.5 MW, 84.1 percent use diesel and 15.9 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-17 Onsite generation fuel type (MW): 2024/2025 Delivery Year

	2024/2025	
Fuel Type	MW	Percent
Diesel	883.5	84.1%
Natural Gas, Gasoline, Oil, Propane, Waste Products	167.0	15.9%
Total	1,050.5	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity resources measure performance nodally, except for demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small End Use Customers to span an entire zone, which is inconsistent with nodal dispatch.

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year.[54] A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, as defined by the zip code of the enrolled End Use Customer's address, the entire registration must respond. There are currently nine defined dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK, DOM_ASHBURN, DOM_DCA, DOM_PRINWILM and AEP_MARION.[55] The AEP_MARION subzone was added as a result of the June 14-16, 2022, performance assessment event in the Columbus, Ohio area of the AEP Zone.

PJM can remove a defined subzone, and make changes to the subzone, at their discretion. Subzones should not be removed once defined, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK Subzones were removed by PJM. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response.

The subzone design and closed loop interfaces are related. PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set

54 OATT Attachment DD, Section 11.
55 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 13, 2023).

price.[56] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.[57] The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the Rest of RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs. These interfaces correspond to LDAs as defined in RPM.[58]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. This will change beginning in the 2027/2028 Delivery Year when the mandatory compliance window will expand to 24 hours per day. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes, the event is not measured for compliance.

Demand resources currently estimate five minute compliance with an hourly interval meter during PAIs. To accurately measure compliance on a five minute basis, a five minute interval meter is required. All other capacity resources require five minute interval meters, and demand resources should be no different. Demand resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance on a five minute basis to accurately report reductions during demand response events. Measuring compliance on a five minute basis would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity resources and that the penalty structure reflect five minute compliance.[59]

Under the capacity performance design of the capacity market, compliance for potential penalties is measured for DR only during performance assessment intervals (PAI).[60]

The MMU recommended that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a performance assessment interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. For the first seven months of 2023, PJM declared an emergency if pre-emergency or emergency demand response were dispatched. But in an order issued July 28, 2023, effective July 30, 2023, FERC approved proposed revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI).[61] Table 6-18 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2024/2025 and 2025/2026 Delivery Years. There are 8,137.5 nominated MW of demand response for the 2025/2026 Delivery Year, 32.1 percent of the required reserve margin and 29.4 percent of the actual reserve margin for the 2025/2026 Delivery Year.[62]

Table 6-18 Demand response nominated MW compared to reserve margin: 2024/2025 and 2025/2026 Delivery Years[63]

Delivery Year	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
2024/2025	7,220.0	21,398.4	33.7%	24,856.8	29.0%
2025/2026	8,137.5	25,381.0	32.1%	25,116.0	32.4%

56 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software, Docket No. AD10-12-006 (June 23, 2015) <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf>.
57 See the *2018 Annual State of the Market Report for PJM*, Volume 2: Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.
58 "PJM Manual 18: PJM Capacity Market," § 2.3.1, Rev. 61 (July 23, 2025).
59 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 61 (July 23, 2025).
60 OATT § 1 (Performance Assessment Hour).
61 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).
62 See *2025 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market, Table 5-7.
63 Nominated MW totals are Demand Response ICAP corresponding to Demand Response UCAP cleared in RPM auctions for each delivery year. The total nominated MW values do not reflect replacement transactions.

PJM will dispatch demand resources by zone or subzone, or within a PAI area. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. In that case, PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or an Emergency Action Area (EAA).[64] [65] A CAA, or EAA, is an electrically connected area that has the same capacity market price. This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. With full implementation of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Definition of Compliance

PJM's reporting of load management events overstates the performance of demand side capacity resources. Limiting reported compliance to only positive values incorrectly reports compliance. Settlement locations with a negative load reduction value (load increase) are not included in compliance reporting by PJM within registrations or within demand response portfolios. A resource that has load above their PLC during a demand response event has a negative performance value. But PJM does not include the negative performance values in the net performance calculation. PJM limits reported compliance shortfall values to zero MW.

The MMU recommends that PJM correctly report compliance for demand side capacity resources to include negative values above PLC when calculating event compliance across hours and registrations.[66]

Emergency demand response resources that are also registered as economic resources have a calculated CBL for the emergency event days. Demand resources that are not registered as Economic Resources use the three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[67] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage.

The MMU recommends that PJM Manual 11 be revised to require, rather than recommend, that the RRMSE test be applied to all demand resources with a CBL.[68]

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU recommends capping demand reductions based entirely on behind the meter generation at the lower of the generator's economic maximum or actual generation output.

64 CAA is "a geographic area of Zones or sub-Zones that are electrically contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT § 1.

65 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 61 (July 23, 2025).

66 See "Market Monitor Report," MC Webinar <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230620-webinar/item-04---imm-report.ashx> (Accessed July 6, 2023).

67 157 FERC ¶ 61,067 (2016).

68 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.5, Rev. 136 (October 1, 2025).

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a demand resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[69] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as emergency or pre-emergency load response customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events. Three proposals that included language to remove bankrupt customers from a CSP's portfolio failed at the June 7, 2017, Market Implementation Committee.[70] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

69 OA Schedule 1 § 8.2.
70 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Approved Minutes from the Market Implementation Committee*, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx>.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM.[71] The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions so that they can accurately measure compliance and that data be provided to PJM within 24 hours.[72]

On September 19, 2024, the Commission issued an order denying the complaint by Enerwise Global Technologies seeking to use statistical sampling for measuring demand response performance when interval metering is available.[73] Commissioner Chang concurred with the Commission's determination and agreed that using actual metered interval data is the ideal method to measure and verify performance for demand-side resources. Commissioner Chang further noted that it is essential that resources that are procured and compensated in the markets actually deliver on their reliability and economic commitments.[74]

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment, but the testing requirements have been inadequate.[75]

71 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.4.1, Rev. 136 (October 1, 2025).
72 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.
73 See "Order Denying Complaint re Enerwise Global Technologies, LLC v. PJM Interconnection," EL23-104-000 (July 28, 2023).
74 *Id*, Commissioner Chang Statement Concurring at 1.
75 The mandatory response time for Capacity Performance DR is June through October and the following May between 10:00AM to 10:00PM EPT and November through April between 6:00AM through 9:00PM EPT. *See* PJM. "Manual 18: PJM Capacity Market," Rev. 61 (July 23, 2025).

For the 2023/2024 Delivery Year and subsequent delivery years, if a Demand Resource registration is not dispatched by PJM for a Load Management event in a delivery year, then the registration must be tested for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday during June through October or November through March of the relevant delivery year, where the date and time are selected by PJM.[76] All registrations in a zone are tested simultaneously for two hours for each product type. Registration performance is calculated as the two hour average reduction.

If less than 25 percent (by MW) of a CSP's total Demand Resources in a zone fail the test, the CSP may conduct re-tests limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that such re-test(s) must be during the same season, at the same time of day and under approximately the same weather conditions as the prior test. If 25 percent or more (by MW) of a CSP's Demand Resources fail the test, the CSP may request PJM to schedule a one time retest limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test. The request must be made before the 46th day after the test. PJM will select the date and time of the retest during the same season. For the initial PJM scheduled test, PJM schedules, on an alternating basis, one test during June through October or November through March for each delivery year that a test is required. On the first business day of a week, PJM provides notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, PJM posts on its website, and notifies the CSPs directly, the test date and zones.[77] On the test date, CSPs are notified of the start time of the test through the same notification protocol used for an actual event. For any scheduled retest by PJM, by 10:00 EPT the day before the retest, PJM will posts on its website, and notifies the CSPs directly, the retest date. On the retest date, CSPs are notified of the start time of the retest through the same notification protocol used for an event.

While the testing revisions implemented with the 2023/2024 Delivery Year are an improvement, the MMU recommends that load management testing be initiated by PJM with advance notice to CSPs identical to the actual lead time required in an emergency in order to accurately represent the conditions of an emergency event.

Beginning in the 2024/2025 Delivery Year and subsequent delivery years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event.[78] Elections are made on or after June 1 and no later than July 14 after the delivery year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14 after the delivery year. Only one event result (either test event or non-PAI LM event) for each end-use customer site will be used in the zonal test evaluation. The duration of the non-PAI LM event must be at least 30 minutes of a clock hour. The election of non-PAI LM events to be used as zonal test performance will be done at registration lead time level. The non-PAI LM event must have occurred in the same season as the PJM scheduled test. For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.

The ability for test performance to be a substitute for event performance, coupled with the absence of nonperformance penalties, weakens the incentive to perform during non-PAI events. Emergency demand response resources have the same obligation to perform when called upon, regardless of whether the dispatch event occurs as part of a PAI or not.[79] There is no reason therefore to allow CSPs the optionality of testing in lieu of using non-PAI event performance.

Table 6-19 shows the test penalties by delivery year by product type for the 2021/2022 Delivery Year through the 2024/2025 Delivery Year.[80] The shortfall MW are calculated for each CSP by zone. The weighted rate per MW is the average penalty rate paid per MW. Testing shortfalls increased dramatically beginning with the 2023/2024 Delivery Year. The testing shortfall for the

76 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 61 (July 23, 2025).
77 See "Demand Response Test Schedule," <https://pjm.com/markets-and-operations/demand-response/demand-response-test-schedule> (Accessed July 18, 2023).
78 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 61 (July 23, 2025).
79 OATT Attachment K, § 8.5.
80 Not all products received penalties or existed in every delivery year. For example, the Base and Capacity Performance products were not an option for the 2020/2021 Delivery Year.

2024/2025 Delivery Year increased by 134 percent compared to the 2023/2024 Delivery Year. Total Load Management Test Compliance penalties were 15.5 percent of total DR capacity revenues in the 2024/2025 Delivery Year.

The daily load management test failure charge rate for a zonal testing shortfall is equal to the provider's weighted daily revenue rate in such zone plus the greater of 0.20 times the provider's weighted daily revenue rate in such zone, or $20/MW-day. A daily load management test failure charge, equal to the net testing shortfall in the zone times the daily load management test failure charge rate, is applied for each day in the delivery year that the resource was committed. The load management test failure charge is assessed in the August monthly bill, issued in September, after the conclusion of the delivery year.[81] The ex-post nature of the load management test penalty, coupled with a high test failure rate, creates the potential for credit issues. Planned demand resource positions in RPM have a collateral requirement only until such time that a nominated MW quantity of customers are registered in DRHUB sufficient to cover the RPM zonal MW quantity committed.[82] These registrations occur prior to the start of the delivery year. Following the delivery year, at the time the testing penalty is levied, these resources are no longer collateralized. Providers subject to test failure penalties would nonetheless be subject to a retroactive disgorgement of revenues proportional to the shortfall quantity plus the higher of 20 percent of their weighted daily revenue rate or $20/MW-day.

Table 6-19 Test penalties by delivery year: 2021/2022 through 2024/2025 Delivery Years

	2021/2022			2022/2023			2023/2024			2024/2025		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Capacity Performance	23.1	$176.79	$1,487,430	7.1	$97.07	$250,346	391.4	$56.45	$8,087,631	933.4	$53.50	$18,225,318

When describing overall test performance, PJM nets the over and under performance of all resources. Netting overstates the performance and capability of the underlying resources. A resource that tests short of its RPM commitment is subject to a penalty. That penalty is offset neither by the over performance of the provider's other resources nor that of other provider's resources. Additionally, during an actual dispatch event, a resource is only required to perform up to its RPM commitment to avoid penalties. While a resource may demonstrate excess capability during testing, there is no obligation for that capability to be provided during an actual event.

Test results for the 2024/2025 Delivery Year when netted, demonstrate an overall capability of 103 percent of the RPM commitment. Underlying this are 933 MW UCAP of testing deficiencies assessed to individual resources. Testing results for the 2024/2025 Delivery Year also showed a marked difference in performance between CSP and EDC or utility-operated programs. As a general matter, the overall over performance of the EDC program resources offset the overall under performance of non-utility providers in the 2024/2025 Delivery Year. Table 6-20 contrasts the testing performance of resources from utility versus non-utility providers for the 2024/2025 Delivery Year.

Table 6-20 Testing Performance: CSP vs EDC Providers

Provider Type	RPM Commitment MW UCAP	Test Performance MW UCAP	Percent
CSP	6,782.6	6,396.5	94%
EDC	920.4	1,540.8	167%
Overall	7,703.1	7,937.3	103%

81 "PJM Manual 18: PJM Capacity Market," § 9.1.6, Rev. 61 (July 23, 2025).
82 "PJM Manual 18: PJM Capacity Market," § 4.8.2, Rev. 61 (July 23, 2025).

Emergency and Pre-Emergency Load Response Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[83] There are 98.7 percent of nominated MW for the 2025/2026 Delivery Year registered under the full program option. There are 1.3 percent of nominated MW for the 2025/2026 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or the strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only: "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets."[84] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2021/2022 Delivery Year.[85] [86] Demand resources registered with the full option should be required to verify energy offers in excess of $1,000 per MWh. PJM does not require such verification.[87] The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources and that the same cost verification rules applied to generation resources apply to demand resources.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the synchronized reserve market, but not demand resources or economic resources.[88]

Table 6-21 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2024/2025 Delivery Year. The majority of participants, 83.3 percent of locations and 52.8 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2024/2025 Delivery Year. Almost all registrations, 99.7 percent of locations and 98.1 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $137.74 per location and $109.14 per nominated MW.

Table 6-21 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2024/2025 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	49	0.3%	132.6	1.9%	$7.14	$2.64
$1,000-$1,275	2,323	14.3%	2,931.6	41.2%	$137.74	$109.14
$1,275-$1,550	340	2.1%	293.6	4.1%	$0.31	$0.36
$1,550-$1,849	13,534	83.3%	3,755.3	52.8%	$15.37	$55.40
Total	16,246	100.0%	7,113.2	100.0%	$32.53	$74.29

Table 6-22 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2025/2026 Delivery Year. The majority of participants, 76.0 percent of locations and 43.8 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2025/2026 Delivery Year. Almost all registrations, 99.7 percent of locations

83 *Id.*
84 161 FERC ¶ 61,153 at P 8 (2017).
85 139 FERC ¶ 61,057 (2012).
86 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
87 OATT Attachment K Appendix Section 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).
88 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 47 (Oct. 1, 2025).

and 98.0 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $0 to $1,000 per MWh strike prices have the highest average at $175.34 per location, while the shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $87.73 per nominated MW.

Table 6-22 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2025/2026 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	59	0.3%	156.1	2.0%	$175.34	$66.25
$1,000-$1,275	4,459	21.5%	3,784.9	47.9%	$74.47	$87.73
$1,275-$1,550	447	2.2%	497.1	6.3%	$0.21	$0.19
$1,550-$1,849	15,738	76.0%	3,460.2	43.8%	$11.15	$50.70
Total	20,703	100.0%	7,898.4	100.0%	$25.02	$65.57

PRD

Price Responsive Demand, or PRD, in the capacity market is capacity based on a firm commitment to reduce load in response to a defined level of real-time energy prices. A PRD offer is a commitment to reduce energy usage by a defined amount in response to real time energy prices during the delivery year. A PRD offer includes MW quantities that the seller will reduce at defined capacity market reservation prices ($/MW-day). PRD offers change the shape of the VRR Curves used in the capacity market auctions.

PRD is provided by a PJM member that represents retail customers that have the ability to reduce load in response to price. In order to be eligible as PRD, the End Use Customer load must be served under a dynamic retail rate or contractual arrangement linked to, or based upon, a PJM real-time LMP trigger at a substation as electrically close as practical to the applicable load. In order for load to be eligible to be considered as PRD, the end-use customer load must be subject to Supervisory Control as defined in the RAA.[89] End Use Customer loads identified may not sell any other form of demand side management in PJM markets.

PRD must also be curtailed once PJM has declared a Performance Assessment Interval but only if the real-time LMP at the applicable location meets or exceeds the price on the submitted PRD curve at which the load has committed to curtail. The high PRD strike prices mean that PRD could avoid a performance requirement even during a PAI.

In order to commit PRD for a delivery year, a PRD Provider must submit a PRD Plan in advance of the Base Residual Auction which indicates the Nominal PRD Value in MW that the PRD Provider is willing to commit at different reservation prices expressed in ($/MW-day). Additional PRD may participate in the Third Incremental Auction only if the LDA final peak load forecast for the delivery year increases relative to the LDA preliminary peak load forecast used for the Base Residual Auction.

Unlike other capacity resources, once committed, PRD may not be uncommitted or replaced by available capacity resources or Excess Commitment Credits. A PRD Provider may transfer the PRD obligation to another PRD Provider bilaterally. The PRD Provider will receive a Daily PRD Credit ($/MW-day) during the delivery year. A PRD Provider under the FRR Alternative will not be eligible to receive a Daily PRD Credit ($/MW-day) during the delivery year. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year.[90] Table 6-23 shows the Nominated MW of Price Responsive Demand for the 2020/2021 through 2025/2026 Delivery Years.

Table 6-23 Nominated MW of price responsive demand: 2020/2021 through 2025/2026 Delivery Year

Delivery Year	RTO	MAAC	EMAAC	SWMAAC	DPL SOUTH	PEPCO	BGE
2020/2021	558.0	558.0	58.0	500.0	27.0	170.0	330.0
2021/2022	510.0	510.0	75.0	435.0	35.7	195.0	240.0
2022/2023	230.0	230.0	40.0	190.0	19.6	110.0	80.0
2023/2024	235.0	235.0	38.0	197.0	15.4	110.0	87.0
2024/2025	305.0	305.0	35.0	270.0	13.0	110.0	160.0
2025/2026	224.0	224.0	14.0	210.0	0.0	75.0	135.0

89 "PJM Manual 18: PJM Capacity Market," § 3A.3, Rev. 61 (July 23, 2025).

90 There were a total of 558 MW of cleared PRD in the 2020/2021 Delivery Year. See PJM Auction Results, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-results.ashx?la=en>.

The cleared PRD is credited the adjusted zonal clearing price of the LDA in which they cleared. The PRD credits are charged to the load of those LDAs by inclusion in the RPM net load price A PRD Provider receives a PRD Credit for each approved Price Responsive Demand registration on a given day. PRD Credits are determined as:[91]

$$
\begin{aligned}
&\textit{PRD Credit}\\
&= [(\textit{Share of Zonal Nominal PRD Value committed in Base Residual Auction}\\
&* (\textit{Zonal Weather}\\
&- \textit{Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year}\\
&/ \textit{Final Zonal Peak Load Forecast for the Delivery Year})\\
&* \textit{Final Zonal RPM Scaling Factor} * \textit{FPR} * \textit{Final Zonal Capacity Price})\\
&\\
&\textit{plus}\\
&\\
&(\textit{Share of Zonal Nominal PRD Value committed in Third Incremental Auction}\\
&* (\textit{Zonal Weather}\\
&- \textit{Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year}\\
&/ \textit{Final Zonal Peak Load Forecast for the Delivery Year})\\
&* \textit{Final Zonal RPM Scaling Factor} * \textit{FPR} * \textit{Final Zonal Capacity Price}\\
&* \textit{Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage})]
\end{aligned}
$$

Effective with the 2022/2023 Delivery Year, the factor equal to (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the delivery year) is eliminated in the calculation of the PRD Credit.

Table 6-24 shows the PRD Credits for the 2020/2021 through 2025/2026 Delivery Years.[92]

Table 6-24 PRD Credits for 2020/2021 through 2025/2026 Delivery Year

Delivery Year	PRD Credit
2020/2021	$23,649,865.05
2021/2022	$38,282,769.14
2022/2023	$10,702,158.12
2023/2024	$6,169,725.27
2024/2025	$10,782,581.08
2025/2026	$10,848,835.56

91 PJM. "Manual 18: Capacity Market," § 9.4.4, Rev. 61 (July 23, 2025).
92 The total credits for PRD were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates.

A PRD Provider with a daily commitment compliance shortfall in a subzone/zone for RPM or FRR is assessed a Daily PRD Commitment Compliance Penalty. The Daily PRD Commitment Compliance Penalty is determined as:

$$\begin{aligned}&\textit{PRD Commitment Compliance Penalty}\\&\quad = \textit{MW shortfall in the Sub} - \textit{zone}/\textit{Zone}\\&\quad * \textit{Delivery Year Forecast Pool Requirement}\\&\quad * \textit{PRD Commitment Compliance Penalty Rate}\end{aligned}$$

The revenue collected from assessment of the PRD Commitment Compliance Penalty is distributed to all entities that committed Capacity Resources in the RPM Auctions for the relevant delivery year, based on each entity's prorata share of daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

PRD committed in RPM for the current delivery year bids in the PJM Energy Market. PRD Curves may be submitted by PRD Providers in the PJM Energy Market by 1100 at the closing of the day-ahead bid period. PRD Curves submitted by PRD Providers are identified in the day-ahead market software and user interface. PRD bids are modeled in the real-time energy market only, and are modeled in the real-time dispatch algorithms. PRD curves are not modeled in the day-ahead market clearing process. PRD Curves in the energy market are modeled in the real-time dispatch algorithms and can set real-time LMP. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to real-time LMPs for the PRD Curves that are submitted. The maximum bid price of the PRD Curve is the applicable energy market offer cap plus the shortage penalty, or $1,849 per MWh. When PRD sellers offer at the cap, they limit the number of times that PRD is called on to respond. The ability to use the strike price which is above the maximum offer for generation resources and above the energy market price for most intervals permits PRD to economically withhold and renders the PRD resources effectively worthless under almost all circumstances.

On February 7, 2019, PJM filed revisions to its Open Access Transmission Tariff and the Reliability Assurance Agreement to update the rules and requirements for PRD to conform to those for Capacity Performance Resources.[93] PJM's filing sought to change the calculation of the Nominal PRD Value used for determining the PRD Credit from the reduction in load during PJM's annual peak to the lesser of summer and winter load reductions. The proposed changes were intended to ensure that PRD will be available to curtail the same quantity of MW in either the summer or the winter consistent with the requirements of Capacity Performance Resources. In an order issued June 27, 2019, the Commission rejected PJM's proposal finding that it was unjust and unreasonable to calculate the Nominal PRD Value in a manner inconsistent with how an LSE's capacity obligation is determined, and therefore saw no need for consistency between the PRD requirements and the requirements for capacity resources.[94] While treated as an annual product, PRD resources are largely comprised of utility retail programs designed to reduce electric load during periods of high load and/or high wholesale energy prices during the summer season. PRD resources consequently performed poorly when called upon during Winter Storm Elliott for the small number of intervals in which LMP exceeded the strike price.[95]

The PRD rules fall short of defining an effective and efficient product that is aligned with the definition of a capacity resource.[96] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[97] PJM's final filing adopted the MMU's recommendation to exclude the use of Winter Peak Load (WPL) when calculating the nominated MW for PRD resources used to satisfy RPM commitments. Load is allocated capacity obligations based on the annual peak load within PJM. The amount of capacity allocated to load is a function solely of summer coincident peak demand and is unaffected by winter demand. Use of the WPL to calculate the nominated MW for PRD resources to satisfy RPM commitments, would incorrectly restrict PRD to less than the total capacity the customer is required to buy. PJM's adoption of the MMU recommendation correctly values PRD nominated MW. FERC required and PJM's filing also adopted the MMU's recommendation that PRD should be eligible for bonus performance payments

93 See "Proposed Amendments to Price Response Demand Rules", Docket No. ER19-1012-000 (Feb. 7, 2019).
94 167 FERC ¶ 61,268
95 See the *2023 Quarterly State of the Market Report for PJM: January through June*, Section 6: Demand Response, Table 6-49.
96 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).
97 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).

during Performance Assessment Intervals (PAI) only when PRD resources respond above their nominated MW value. Allowing PRD resources to collect bonus payments at times when they are not even required to meet their basic obligation would be inconsistent with the basic CP construct as it applies to all other CP resources.[98]

PJM's filing still fell short of completely aligning PRD with the definition of capacity. PRD resources do not have to respond during a PAI if the PRD's trigger price is above LMP during the PAI. All other CP resources have the obligation to perform during a PAI, regardless of the real-time LMP, subject to instructions from PJM. PRD should be held to the same standard during a PAI event. The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources.

June 23-25, 2025 Load Management Event

PJM dispatched pre-emergency load management during a period of hot weather on June 23-25, 2025. Long lead time (120 minute) and short lead-time (60 minute) pre-emergency resources were dispatched each day. PJM never declared a level EEA2 emergency, the requirement for deployment of emergency demand response resources, and therefore only dispatched pre-emergency demand resources.[99]

PJM did not dispatch quick lead time (30 minute) demand resources. PJM used the less flexible 60 and 120 minute lead time resources first. The 60 and 120 minute lead time resources were more economical as they are subject to $1,425 and $1,100 maximum strike prices compared to the $1,849 maximum strike price for 30 minute resources.

On June 23, 2025, PJM dispatched 1,299.3 MW of 120 minute lead time (34.6 percent of total pre-emergency 120 minute resources) and 114.0 MW of 60 minute lead time (24.7 percent of total pre-emergency 60 minute resources). On June 24, 2025, PJM dispatched 3,755.5 MW of 120 minute lead time (100 percent of total pre-emergency 120 minute resources) and 462.0 MW of 60 minute lead time (100 percent of total pre-emergency 60 minute resources). On June 25, 2025, PJM dispatched 1,604.5 MW of 120 minute lead time (42.7 percent of total pre-emergency 120 minute resources) and 123.9 MW of 60 minute lead time (26.8 percent of total pre-emergency 60 minute resources).[100]

Load management compliance data for non-PAI event performance is due 45 days after the month in which the event occurs.[101] Data supporting requested energy settlements is due 60 days after an event.[102]

Table 6-25 through Table 6-27 show the deployment and release times, by lead time, for June 23-25, 2025.

Table 6-25 Demand Resource Deployment and Release Times: June 23, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	2200	Pre-emergency	120 minute	AECO, BGE, DOM, DPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	2200	Pre-emergency	60 minute	AECO, BGE, DOM, DPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG

Table 6-26 Demand Resource Deployment and Release Times: June 24, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	2200	Pre-emergency	120 minute	BGE, DOM, PECO, PEPCO
1530	2200	Pre-emergency	120 minute	AECO, DPL, JCPL, METED, PENELEC, PPL, PSEG
1600	2200	Pre-emergency	120 minute	AEP, APS, DAY, DUQ
1630	2200	Pre-emergency	120 minute	ATSI, COMED, DEOK, EKPC
1500	2200	Pre-emergency	60 minute	BEG, DOM, PECO, PEPCO
1530	2200	Pre-emergency	60 minute	AECO, DPL, JCPL, METED, PENELEC, PPL, PSEG
1600	2200	Pre-emergency	60 minute	AEP, APS, DAY, DUQ
1630	2200	Pre-emergency	60 minute	ATSI, COMED, DEOK, EKPC

98 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).
99 OATT Attachment K, Section 8.5.
100 Reported MW are on a nominated ICAP basis.
101 "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 61 (July 23, 2025).
102 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.4.1, Rev. 136 (October 1, 2025).

Table 6-27 Demand Resource Deployment and Release Times: June 25, 2025

Deploy Time (EPT)	Release Time (EPT)	Resource Type	Lead Time	Zones
1500	1745	Pre-emergency	120 minute	APS
1500	1810	Pre-emergency	120 minute	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	1900	Pre-emergency	120 minute	DOM
1500	1745	Pre-emergency	60 minute	APS
1500	1810	Pre-emergency	60 minute	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG
1500	1900	Pre-emergency	60 minute	DOM

The emergency procedures employed during June 23-25, 2025 did not trigger a PAI. There are no penalties for demand resources failing to perform outside of a PAI. In an order issued July 28, 2023, effective July 30, 2023, FERC approved proposed revisions to PJM's Tariff to eliminate the dispatch of demand response as a trigger for calling an emergency and for defining a Performance Assessment Interval (PAI).[103] Under the prior rules, PJM would declare an emergency if pre-emergency or emergency demand response was dispatched. The new rules mean that demand resources may be dispatched both as part of, and absent, a PAI. While demand resources dispatched during a PAI continue to be subject to Non-Performance Assessment charges, demand resources dispatched outside of a PAI are not subject to any event specific penalties.[104] If a demand resource is dispatched only outside of Performance Assessment Events for the delivery year, its performance for the delivery year may be determined based solely on a Load Management Test.[105] Beginning in the 2024/2025 Delivery Year and subsequent delivery years, CSPs may elect to use performance data from a load management event that was not subject to a Non-Performance Assessment (a non-PAI load management event) as performance data for a PJM zonal test event.[106]

Given that calling demand resources no longer triggers a PAI, the MMU recommended in 2023 that PJM revise the performance requirements for demand resources to include an event specific measurement for dispatch occurring outside of Performance Assessment Events and penalties for nonperformance. Load management resources have the same obligation to perform when called upon, regardless of whether the dispatch event occurs as part of a PAI or not.[107] There is no reason therefore to allow CSPs the optionality of testing in lieu of using non-PAI event performance. If demand resources are only subject to non-PAI dispatch events during the delivery year, their ability to meet their obligations are best defined by their actual operational performance rather than through a scripted test.

Load management resources overall failed to perform to their committed ICAP level during the June 23-25, 2025 dispatch event. Load management resources were evaluated based on their ability to reduce load to their nominated Firm Service Level (FSL). Customer Base Line (CBL) is an hourly estimate of the load level of a demand resource in the absence of a demand response event. The expected hourly reduction of each resource is defined as the difference between the CBL and the FSL. The actual hourly reduction is defined as the difference between the CBL and the metered load of the resource adjusted for losses. If a resource reduces to its FSL, then its actual reduction equals its expected reduction. This metric provides a better assessment of demand response performance than simply comparing metered load to FSL. During Winter Storm Elliott, demand resource loads were already at a reduced level when dispatched. While deemed to have generally met their ICAP commitments, there was very little incremental reduction provided in order to reach their FSL. The difference between CBL and FSL provides a better estimate of the expected incremental reduction. If a dispatched registration has a CBL equal to or less than the FSL, the expected incremental reduction is zero. Based on this metric, demand resources provided 69.3 percent of their expected reduction on June 23, 70.6 percent of their expected reduction on June 24 and 68.8 percent of their expected reduction on June 25. Table 6-28 summarizes these results.

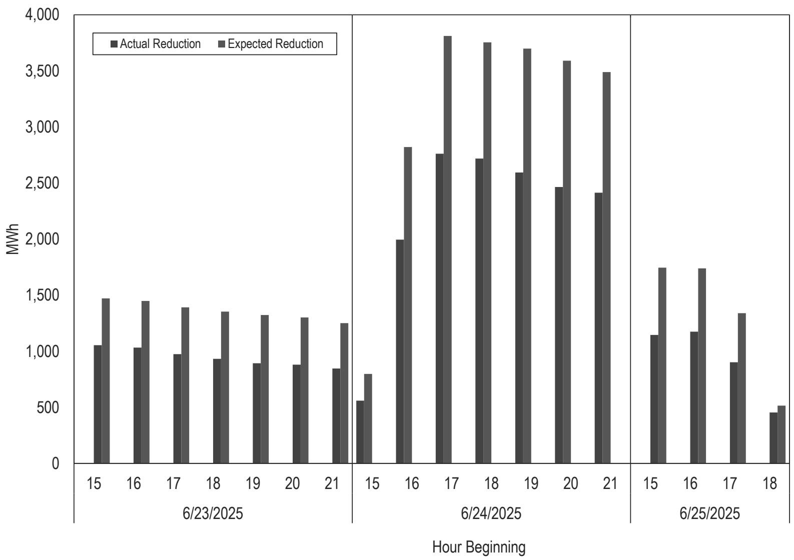
103 See "Order Accepting Tariff Revisions Subject to Condition," Docket No. ER23-1996-000 (July 28, 2023).
104 "PJM Manual 18: PJM Capacity Market," § 8.6, Rev. 61 (July 23, 2025).
105 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 61 (July 23, 2025).
106 "PJM Manual 18: PJM Capacity Market," § 8.7, Rev. 61 (July 23, 2025).
107 OATT Attachment K, § 8.5.

Table 6-28 Demand Resource Expected and Actual Performance: June 23-25, 2025

Date	Actual Reduction (MWh)	Expected Reduction (MWh)	Percent Performance
23-Jun-25	6,614	9,540	69.3%
24-Jun-25	15,506	21,963	70.6%
25-Jun-25	3,675	5,339	68.8%
Total	25,796	36,842	70.0%

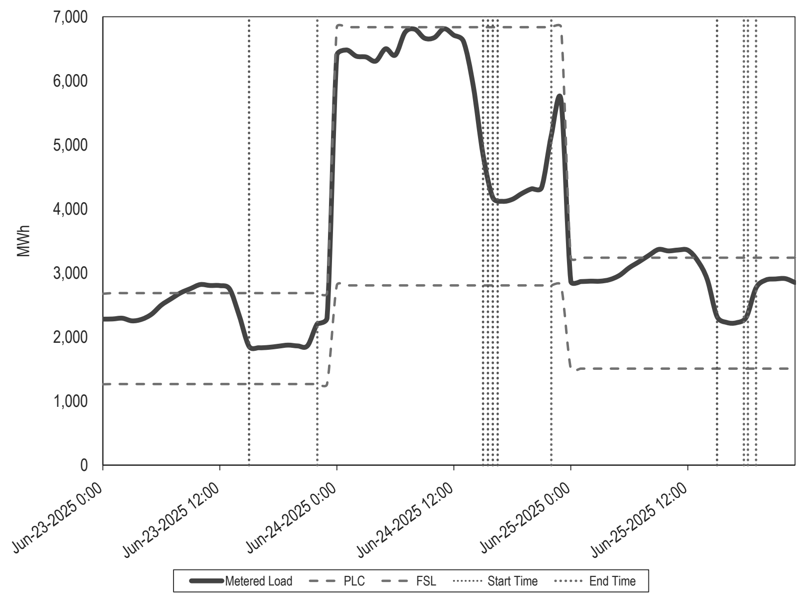
Figure 6-2 shows the hourly expected and actual reduction values for June 23-25, 2025.

Figure 6-2 Hourly demand resource expected and actual performance: June 23-25, 2025



The failure of demand resources overall to perform to their committed ICAP level is further evidenced by observing the metered load relative to the Peak Load Contribution (PLC) and FSL. As shown in Figure 6-3, demand resources overall failed to reduce load to their FSL on all three days that they were dispatched.

Figure 6-3 Demand resource metered load compared to PLC and FSL: June 23-25, 2025



Load management demand resources are compensated at real-time LMP for their actual load reduction determined as the difference between the CBL and the metered load. Load management demand resources are paid an emergency load response energy credit equal to their actual load reduction multiplied by the real-time LMP. Load management demand resources are made whole to their offer value which includes their emergency bid price, or strike price and shutdown costs. If the emergency load response energy credit is insufficient to cover the emergency bid based reduction plus shutdown costs, they will receive an emergency load response make whole credit for the difference.

$$\begin{aligned}&\textit{Total Emergency Energy Revenue}\\&\quad = \textit{Daily Load Response Emergency Credits}\\&\quad + \textit{Emergency Load Response Make Whole Credit}\end{aligned}$$

where,

$$\begin{aligned}&\textit{Emergency Load Response Make Whole Credit}\\&\quad = \textit{Emergency Bid cost} + \textit{Emergency Shutdown cost}\\&\quad - \textit{Daily Load Response Emergency Credits}\end{aligned}$$

Table 6-29 shows the daily emergency energy payments to load management demand resources for June 23-25, 2025. Across the three days, real-time LMP was sufficient to cover 51 percent of the total emergency energy payments with the remainder compensated through make whole credits. These energy payments are in addition to the capacity market revenues received by load management demand resources. For the 2025/2026 Delivery Year, capacity market revenues paid to load management demand resources average $55.5 million per month.

Table 6-29 Demand resource emergency energy payments: June 23-25, 2025

Date	Real-Time Actual Relief (MWh)	Average Emergency Bid Price	Average Emergency Shutdown Cost	Average LMP	Emergency Load Response Energy Credit	Emergency Load Response Energy Make-Whole Credit	Total Emergency Energy Revenue
23-Jun-25	7,397	$1,143	$48	$555	$4,105,528	$3,616,557	$7,722,084
24-Jun-25	19,096	$1,134	$82	$662	$12,639,948	$8,862,562	$21,502,510
25-Jun-25	5,149	$1,132	$72	$212	$1,092,332	$4,347,255	$5,439,587
Total	31,642	$1,136	$67	$564	$17,837,807	$16,826,374	$34,664,181

Economic Demand Response

The Economic Demand Response Program is for demand response customers that offer into the day-ahead or real-time energy market.[108] The estimated load reduction is paid the zonal LMP, as long as the zonal LMP is greater than the monthly Net Benefits Test threshold.

Market Structure

Table 6-30 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2024, through September 30, 2025. The ownership of economic demand response resources was highly concentrated in 2024 and the first nine months of 2025.[109] Table 6-30 lists the share of reported reductions provided by, and the share of credits claimed by the four largest CSPs in each year. The HHI for economic demand response was highly concentrated in the first nine months of 2025. The HHI for economic demand response in the first nine months of 2025 decreased by 46, 0.5 percent, from 8846 in the first nine months of 2024 to 8800 in the first nine months of 2025.

108 Also known in the PJM Market Rules as the Economic Load Response Program.
109 All HHI calculations in this section are at the parent company level.

Table 6-30 Average hourly MWh HHI and market concentration in the economic program: January 2024 through September 2025[110]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	2024	2025	Percent Change	2024	2025	Change in Percent	2024	2025	Change in Percent
Jan	9043	8382	(7.3%)	100.0%			100.0%		
Feb	8806	8017	(9.0%)						
Mar	9856	8510	(13.7%)						
Apr	9566	8547	(10.7%)	100.0%			100.0%		
May	9722	8655	(11.0%)	100.0%			100.0%		
Jun	8405	9228	9.8%	99.8%			99.7%		
Jul	8249	8963	8.7%	99.6%			99.4%		
Aug	7913	8977	13.5%	99.9%			99.8%		
Sep	8052	9919	23.2%						
Oct	9400								
Nov	8121								
Dec	7745								
Total	8684	8709	0.3%	99.9%			99.8%		

Market Performance

Table 6-31 shows the total MW reported reductions made by participants in the economic program and the total credits paid for these reported reductions in the first nine months of 2010 through 2025. The average credits per MWh paid increased by $5.77 per MWh, 10.9 percent, from $52.76 per MWh in the first nine months of 2024 to $58.53 per MWh in the first nine months of 2025. Curtailed energy for the economic program was 350,396 MWh in the first nine months of 2025, an increase of 184,584 MWh, 111.3 percent, as compared to curtailed energy for the economic program in the first nine months of 2024. Total credits paid for the economic load response program in the first nine months of 2025 were $20,508,803, an increase of $11,760,026, 134.4 percent, compared to the total credits paid for the economic load response program in the first nine months of 2024.

110 Omitted reduction and credit share values are based on confidentiality rules that require published data to include more than four owners.

Table 6-31 Credits paid to economic program participants: January through September, 2010 through 2025

(Jan-Sep)	Total MWh	Total Credits	$/MWh
2010	58,280	$2,677,937	$45.95
2011	15,376	$1,943,507	$126.40
2012	121,381	$8,172,654	$67.33
2013	105,299	$7,387,658	$70.16
2014	118,007	$16,510,733	$139.91
2015	103,721	$7,355,263	$70.91
2016	67,516	$3,032,039	$44.91
2017	49,331	$2,167,590	$43.94
2018	44,735	$2,360,007	$52.76
2019	21,163	$860,235	$40.65
2020	8,329	$289,129	$34.71
2021	15,670	$935,370	$59.69
2022	59,370	$6,408,156	$107.94
2023	34,546	$2,342,794	$67.82
2024	165,812	$8,748,777	$52.76
2025	350,396	$20,508,803	$58.53

Economic demand response resources that are dispatched by PJM in both the economic and emergency programs are paid the higher price defined in the emergency rules.[111] For example, assume a demand resource has an economic offer price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the day-ahead energy market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear.[112] All other resources that clear in the day-ahead market are financially firm at the clearing price. Payment at a guaranteed strike price and the ability to set energy market prices at the strike price effectively grant the seller the right to exercise market power.

Figure 6-4 shows monthly economic demand response credits and MWh, from January 1, 2010, through September 30, 2025.

111 "PJM. Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 136 (October 1, 2025).
112 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016) ("Order No. 831").

Figure 6-4 Economic program credits and MWh by month: 2010 through September 2025

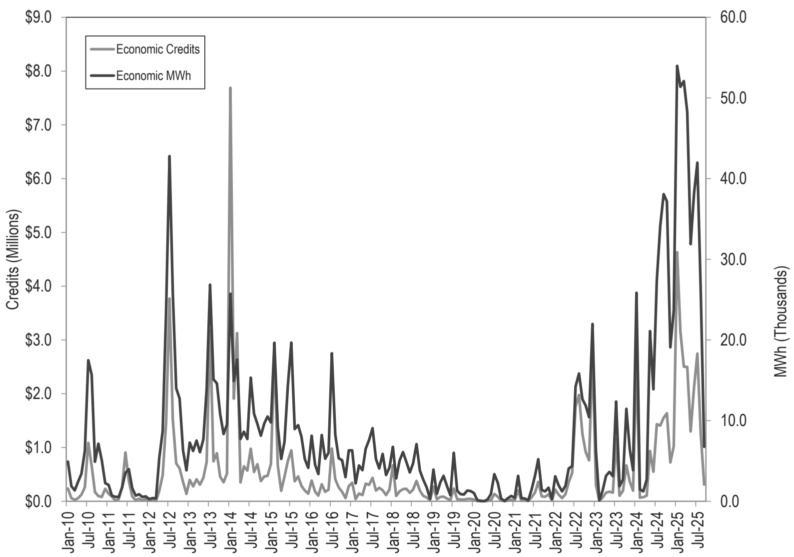


Table 6-32 shows performance for the first nine months of 2024 and 2025 in the economic program by control zone. Total reported reductions under the economic program increased by 184,584 MWh, 111.3 percent, from 165,812 MWh in the first nine months of 2024 to 350,396 MWh in the first nine months of 2025. Total revenue under the economic program increased by $11.8 million, 134.4 percent, from $8.7 million in the first nine months of 2024 to $20.5 million in the first nine months of 2025.[113]

Emergency and economic demand response energy payments are uplift and not compensated by LMP revenues. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[114] The zonal allocation is shown in Table 6-32.

113 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-32. Payments for Economic demand response reductions are settled monthly.

114 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 98 (Dec. 17, 2024).

Table 6-32 Economic program participation by zone: January through September, 2024 and 2025

	Credits			MWh Reductions			Credits per MWh Reduction		
Zone	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change
ACEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	$3,095,311.09	$8,154,481.45	163.4%	73,359	143,344	95.4%	$42.19	$56.89	34.8%
APS	$363,667.36	$822,814.13	126.3%	9,118	16,864	85.0%	$39.89	$48.79	22.3%
ATSI	$1,336,607.55	$3,103,201.15	132.2%	10,931	25,113	129.7%	$122.28	$123.57	1.1%
BGE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
COMED	$20,935.75	$33,493.00	60.0%	646	910	40.9%	$32.40	$36.79	13.6%
DAY	$0.00	($4,695.51)	NA	0	0	NA	NA	NA	NA
DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	$3,671,795.23	$8,167,076.25	122.4%	69,703	162,284	132.8%	$52.68	$50.33	(4.5%)
DOM	$0.00	$75,609.61	NA	0	301	NA	NA	$251.13	NA
DPL	$50,485.49	$0.00	NA	149	0	NA	$339.04	NA	NA
JCPLC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
MEC	$23,149.54	$14,832.14	(35.9%)	275	140	(49.2%)	$84.24	$106.29	26.2%
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$28,932.90	$38,599.10	33.4%	456	575	25.9%	$63.40	$67.18	6.0%
PE	$15,295.92	$0.00	NA	119	0	NA	$128.04	NA	NA
PEPCO	$0.00	$2,064.47	NA	0	28	NA	NA	$73.75	NA
PPL	$135,329.43	$6,078.27	(95.5%)	937	26	(97.2%)	$144.40	$235.62	63.2%
PSEG	$7,267.20	$95,249.24	1,210.7%	120	812	578.2%	$60.73	$117.37	93.3%
REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	$8,748,777.46	$20,508,803.31	134.4%	165,812	350,396	111.3%	$52.76	$58.53	10.9%

Table 6-33 shows average reported MWh reductions and credits by hour for the first nine months of 2024 and 2025. The average LMP during Load Response is the reduction weighted average hourly DA or RT load-weighted LMP during the economic load response hour. In the first nine months of 2024, 71.4 percent of the reported reductions and 73.8 percent of credits occurred in hours ending 0900 EPT to 2100 EPT, and in the first nine months of 2025, 62.9 percent of the reported reductions and 64.4 percent of credits occurred in hours ending 0900 EPT to 2100 EPT. The average LMP during load response increased by $12.98 per MWh, 27.7 percent, from $46.88 per MWh in the first nine months of 2024 to $59.86 per MWh in the first nine months of 2025.

Table 6-33 Hourly frequency distribution of economic program reported MWh reductions and credits: January through September, 2024 and 2025

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change
1 through 6	11,585	44,922	288%	$652,293	$2,389,503	266%	$50.63	$47.70	(6%)
7	5,856	16,069	174%	$294,030	$997,589	239%	$42.89	$58.17	36%
8	6,746	16,998	152%	$369,487	$1,121,368	203%	$46.03	$64.05	39%
9	5,166	14,939	189%	$250,703	$823,991	229%	$39.67	$49.55	25%
10	6,130	13,765	125%	$277,982	$682,772	146%	$38.36	$45.91	20%
11	6,966	14,393	107%	$311,749	$728,496	134%	$38.73	$47.66	23%
12	7,751	14,530	87%	$348,322	$737,569	112%	$40.74	$46.98	15%
13	8,474	14,993	77%	$392,204	$789,562	101%	$42.13	$48.76	16%
14	8,754	14,883	70%	$430,986	$817,160	90%	$44.95	$50.48	12%
15	8,746	13,694	57%	$454,979	$706,542	55%	$48.21	$52.17	8%
16	9,091	13,955	53%	$485,778	$760,859	57%	$50.39	$57.24	14%
17	10,711	15,955	49%	$656,985	$946,854	44%	$57.77	$61.30	6%
18	12,321	19,872	61%	$845,668	$1,300,135	54%	$65.71	$71.72	9%
19	11,737	22,307	90%	$746,617	$1,526,197	104%	$58.99	$73.73	25%
20	11,841	24,166	104%	$702,559	$1,769,483	152%	$53.44	$81.04	52%
21	10,779	23,092	114%	$548,020	$1,611,650	194%	$46.72	$70.32	51%
22	9,643	20,316	111%	$446,795	$1,183,838	165%	$42.34	$56.20	33%
23 through 24	13,515	31,547	133%	$533,622	$1,615,235	203%	$36.16	$94.57	162%
Total	165,812	350,396	111%	$8,748,777	$20,508,803	134%	$46.88	$59.86	30%

Table 6-34 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in the first nine months of 2024 and 2025. In the first nine months of 2025, 2.4 percent of reported MWh reductions and 9.7 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-34 Frequency distribution of economic program zonal load-weighted average LMP (By hours): January through September, 2024 and 2025

	MWh Reductions			Program Credits		
LMP	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change
$0 to $25	12,891	397	(97%)	$278,937	$7,130	(97%)
$25 to $50	94,840	195,494	106%	$3,502,867	$7,529,012	115%
$50 to $75	31,632	93,464	195%	$1,874,751	$5,641,324	201%
$75 to $100	8,705	29,783	242%	$720,528	$2,562,018	256%
$100 to $125	6,684	13,514	102%	$724,040	$1,489,906	106%
$125 to $150	6,846	6,391	(7%)	$895,952	$820,659	(8%)
$150 to $175	2,604	2,982	15%	$393,060	$467,952	19%
> $175	1,610	8,373	420%	$358,643	$1,990,802	455%
Total	165,812	350,396	111%	$8,748,777	$20,508,803	134%

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-35 shows the sum of real-time and day-ahead Economic Load Response charges paid in each zone and paid by exports. In the first nine months of 2025, DOM Zone has paid the highest Economic Load Response charges.

Table 6-35 Zonal Economic Load Response charge: January through September, 2025[115]

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$48,626	$32,112	$23,398	$17,654	$11,557	$24,253	$39,656	$14,417	$3,722	$215,395
AEP	$742,329	$489,401	$402,850	$404,165	$184,147	$330,974	$404,419	$196,473	$50,674	$3,205,431
APS	$296,622	$191,496	$160,016	$146,549	$67,944	$117,406	$146,238	$66,917	$16,843	$1,210,031
ATSI	$341,093	$237,093	$210,668	$205,588	$83,847	$167,016	$210,480	$95,894	$23,345	$1,575,022
BGE	$185,335	$118,543	$98,599	$98,136	$49,790	$80,819	$102,469	$43,328	$11,132	$788,152
COMED	$336,266	$292,798	$152,468	$139,902	$105,832	$241,087	$309,365	$149,168	$31,687	$1,758,575
DAY	$95,107	$64,474	$53,070	$55,402	$26,975	$44,780	$56,180	$27,465	$6,499	$429,951
DUKE	$144,143	$95,862	$76,538	$79,411	$36,708	$70,017	$86,779	$40,935	$10,126	$640,519
DUQ	$66,568	$44,192	$38,251	$37,344	$15,491	$34,361	$43,914	$19,907	$4,584	$304,612
DOM	$730,501	$478,676	$413,741	$443,106	$220,167	$337,845	$404,508	$181,128	$48,094	$3,257,766
DPL	$113,836	$73,521	$46,255	$33,805	$20,898	$39,464	$63,661	$24,264	$6,423	$422,127
EKPC	$101,608	$62,099	$43,140	$38,704	$18,299	$33,921	$42,571	$20,489	$4,975	$365,806
JCPLC	$110,394	$74,496	$60,250	$43,238	$26,585	$57,157	$86,048	$31,503	$8,072	$497,743
MEC	$84,800	$56,750	$47,100	$33,518	$24,718	$35,271	$46,593	$18,373	$4,755	$351,879
OVEC	$579	$454	$382	$354	$138	$202	$256	$123	$34	$2,520
PECO	$210,523	$139,657	$91,232	$62,224	$43,003	$79,060	$126,073	$48,826	$13,280	$813,877
PE	$90,525	$64,985	$55,621	$48,995	$22,826	$39,300	$48,211	$21,620	$5,410	$397,492
PEPCO	$168,433	$107,854	$89,877	$88,287	$48,903	$75,620	$94,645	$39,066	$10,346	$723,030
PPL	$237,574	$155,164	$120,527	$88,161	$45,933	$83,762	$118,996	$43,845	$11,738	$905,700
PSEG	$209,242	$145,350	$117,250	$85,034	$52,679	$105,954	$152,549	$58,388	$15,519	$941,966
REC	$6,462	$4,591	$4,059	$2,989	$1,884	$4,253	$5,737	$2,271	$553	$32,798
Exports	$310,870	$222,254	$197,109	$344,687	$190,689	$126,905	$157,372	$95,729	$22,798	$1,668,412
Total	$4,631,435	$3,151,821	$2,502,401	$2,497,252	$1,299,013	$2,129,425	$2,746,720	$1,240,128	$310,607	$20,508,803

115 Load response charges were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates.

Table 6-36 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in the first nine months of 2025.[116]

Table 6-36 Zonal economic load response charge per GWh of load and exports: January through September, 2025

Zone	January	February	March	April	May	June	July	August	September	Zonal Average
ACEC	$0.055	$0.045	$0.035	$0.028	$0.017	$0.026	$0.032	$0.015	$0.005	$0.029
AEP	$0.056	$0.045	$0.038	$0.041	$0.018	$0.028	$0.031	$0.016	$0.005	$0.031
APS	$0.057	$0.045	$0.041	$0.041	$0.019	$0.029	$0.031	$0.016	$0.005	$0.032
ATSI	$0.055	$0.043	$0.040	$0.042	$0.017	$0.028	$0.031	$0.016	$0.005	$0.031
BGE	$0.058	$0.046	$0.043	$0.048	$0.023	$0.030	$0.032	$0.017	$0.005	$0.034
COMED	$0.040	$0.040	$0.022	$0.021	$0.016	$0.028	$0.031	$0.016	$0.004	$0.024
DAY	$0.056	$0.045	$0.039	$0.044	$0.021	$0.029	$0.032	$0.017	$0.005	$0.032
DUKE	$0.056	$0.045	$0.038	$0.042	$0.019	$0.029	$0.031	$0.017	$0.005	$0.031
DUQ	$0.054	$0.043	$0.038	$0.041	$0.016	$0.029	$0.031	$0.016	$0.005	$0.030
DOM	$0.057	$0.046	$0.042	$0.047	$0.022	$0.029	$0.031	$0.016	$0.005	$0.033
DPL	$0.057	$0.047	$0.033	$0.027	$0.016	$0.024	$0.032	$0.015	$0.005	$0.028
EKPC	$0.061	$0.049	$0.040	$0.042	$0.019	$0.029	$0.032	$0.017	$0.005	$0.033
JCPLC	$0.055	$0.044	$0.039	$0.030	$0.017	$0.028	$0.033	$0.016	$0.005	$0.030
MEC	$0.056	$0.044	$0.040	$0.031	$0.023	$0.027	$0.031	$0.015	$0.004	$0.030
OVEC	$0.048	$0.043	$0.037	$0.039	$0.016	$0.025	$0.028	$0.014	$0.004	$0.028
PECO	$0.056	$0.044	$0.031	$0.023	$0.016	$0.023	$0.031	$0.014	$0.004	$0.027
PE	$0.056	$0.046	$0.042	$0.040	$0.019	$0.029	$0.031	$0.016	$0.005	$0.031
PEPCO	$0.058	$0.047	$0.043	$0.046	$0.024	$0.030	$0.032	$0.016	$0.005	$0.033
PPL	$0.056	$0.043	$0.037	$0.030	$0.016	$0.025	$0.030	$0.013	$0.004	$0.028
PSEG	$0.055	$0.045	$0.038	$0.029	$0.017	$0.027	$0.032	$0.015	$0.005	$0.029
REC	$0.054	$0.045	$0.040	$0.031	$0.018	$0.031	$0.033	$0.017	$0.005	$0.030
Exports	$0.063	$0.051	$0.044	$0.098	$0.046	$0.027	$0.029	$0.016	$0.005	$0.042
Monthly Average	$0.056	$0.045	$0.038	$0.039	$0.020	$0.028	$0.031	$0.016	$0.005	$0.031

116 Load response charges were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates.

Table 6-37 shows the monthly day-ahead and real-time Economic Load Response charges for the first nine months of 2024 and 2025. The day-ahead Economic Load Response charges increased by $11.8 million, 139.2 percent, from $8.5 million in the first nine months of 2024 to $20.3 million in the first nine months of 2025. The real-time Economic Load Response charges decreased $80,188, 0.1 percent, from $248,499 in the first nine months of 2024 to $168,311 in the first nine months of 2025.[117]

Table 6-37 Monthly day-ahead and real-time economic load response charge: January 2024 through September 2025

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	2024	2025	Percent Change	2024	2025	Percent Change
Jan	$2,598,194	$4,606,508	77.3%	$23,442	$24,927	6.3%
Feb	$63,832	$3,044,896	4,670.2%	$3,723	$106,925	2,772.1%
Mar	$75,020	$2,490,135	3,219.3%	$586	$12,266	1,993.8%
Apr	$101,710	$2,489,382	2,347.5%	$2,021	$7,870	289.5%
May	$933,721	$1,292,724	38.4%	$2,473	$6,289	154.4%
Jun	$522,354	$2,126,584	307.1%	$28,167	$2,841	(89.9%)
Jul	$1,285,277	$2,742,413	113.4%	$148,484	$4,308	(97.1%)
Aug	$1,373,874	$1,237,243	(9.9%)	$32,880	$2,885	(91.2%)
Sep	$1,548,879	$310,607	(79.9%)	$6,724	$0	(100.0%)
Oct	$1,633,066			$3,796		
Nov	$745,348			$932		
Dec	$1,015,838			$7,132		
Total (Jan-Sept)	$8,502,861	$20,340,492	139.2%	$248,499	$168,311	(32.3%)

Table 6-38 shows registered sites and MW for the last day of each month for the period January 1, 2021, through September 30, 2025. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations increased by 85, 17.1 percent, from 496 in the first nine months of 2024 to 581 in the first nine months of 2025. Average monthly registered MW decreased by 14 MW, 0.5 percent, from 3,156 MW in the first nine months of 2024 to 3,142 MW in the first nine months of 2025.

Most economic demand response resources are registered in the emergency demand response program. Resources registered in both programs do not need to register for the same amount of MW. There are 184 economic registrations and 190 capacity registrations in the emergency program that share the same location IDs in both programs. There are 1,616.4 nominated economic MW, 51.4 percent of all economic MW and 1,326.8 nominated capacity MW, 16.6 percent of all nominated capacity MW in the emergency program that share the same location IDs in both programs.

117 Load response charges were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates. Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included. Payments for Economic demand response reductions are settled monthly.

Table 6-38 Economic program registrations on the last day of the month: 2021 through September 2025[118]

	2021		2022		2023		2024		2025	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	277	1,495	323	2,233	347	2,874	462	3,176	564	2,984
Feb	275	1,503	323	2,256	354	2,870	472	3,299	577	3,017
Mar	284	1,514	330	2,377	361	2,930	476	3,244	588	3,169
Apr	293	1,538	330	2,382	373	2,932	481	3,207	581	3,160
May	319	1,658	326	2,377	378	3,006	487	3,230	586	3,278
Jun	313	2,136	315	2,323	396	2,929	501	2,942	582	3,150
Jul	312	2,105	310	2,412	412	3,096	524	3,266	584	3,147
Aug	322	2,122	318	2,451	428	3,163	528	3,027	579	3,146
Sep	322	2,256	329	2,565	440	3,335	531	3,017	585	3,225
Oct	332	2,267	333	2,575	453	3,362	543	2,922		
Nov	333	2,270	338	2,593	478	3,499	560	2,948		
Dec	320	2,256	359	2,640	487	3,493	570	2,989		
Avg	309	1,927	328	2,432	409	3,124	511	3,106	581	3,142

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch up to the amount of MW registered in the program, but are not required to offer any MW. Table 6-39 shows the sum of maximum economic MW dispatched by registration each month from January 1, 2013, through September 30, 2025. The monthly maximum is the sum of each registration's monthly noncoincident maximum dispatched MW and annual maximum is the sum of each registration's annual noncoincident maximum dispatched MW. The monthly maximum dispatched MW increased 44.4 MW, 19.0 percent, in the first nine months of 2025 compared to 2024.[119]

Table 6-39 Sum of maximum MW reported reductions for all registrations per month: 2013 through September 2025

	Sum of Peak MW Reductions for all Registrations per Month												
Month	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jan	193	446	169	139	123	142	88	28	21	34	50	281	404
Feb	119	307	336	128	83	70	58	11	86	34	18	102	409
Mar	127	369	198	120	111	71	38	12	20	30	53	102	271
Apr	133	146	143	118	54	71	41	3	22	43	70	84	245
May	192	151	161	131	169	70	22	12	9	53	141	247	152
Jun	433	483	833	121	240	105	26	38	125	110	96	213	342
Jul	1,088	665	1,362	1,316	936	518	770	135	134	150	309	469	370
Aug	497	358	272	249	141	581	33	99	827	162	191	376	195
Sep	530	795	816	263	140	112	76	31	35	88	392	223	108
Oct	168	214	136	150	88	69	29	9	31	67	80	344	
Nov	155	166	127	116	81	54	35	12	31	58	88	138	
Dec	168	155	122	147	83	11	31	14	19	116	77	315	
Annual	1,486	1,739	1,858	1,451	1,217	758	830	196	921	263	735	616	578

118 Data for years 2010 through 2017 are available in the *2017 Annual State of the Market Report for PJM*.
119 Maximum MW reductions were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates.

Table 6-40 shows total settlements submitted for 2013 through 2025. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-40 Settlements submitted in the economic program: January through September, 2013 through 2025

(Jan-Sep)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Number of Settlements	2,358	2,425	1,851	1,524	1,417	1,263	875	458	678	1,524	588	1,406	2,764

Table 6-41 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for 2013 through 2025. The number of active participants increased by 8, 20.0 percent, from 40 in the first nine months of 2024 to 48 in the first nine months of 2025. All participants must be registered through a CSP.

Table 6-41 Participants and CSPs submitting settlements in the economic program by year: January through September, 2013 through 2025

(Jan-Sep)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Active CSPs	20	16	18	12	13	13	12	10	11	9	8	6	4
Active Participants	273	154	114	58	72	58	51	29	35	28	29	40	48

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[120] Economic resources offer into the energy market and must provide supporting documentation to offer above $1,000 per MWh. FERC stated, "[t]he offer cap reforms, however, do not apply to capacity-only demand response resources that do not submit incremental energy offers into energy markets."[121] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of FERC Order No. 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

120 157 FERC ¶ 61,115 at P 139 (2016).
121 *Id.* at 8.

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff rates. Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load.

PJM calculates the NBT price threshold by first retrieving generation offers from the same month of the prior calendar year for which the calculation is being performed. PJM then adjusts a portion of each prior year offer, representing the typical share of fuel costs in energy offers in the PJM Region, for changes in fuel prices based on the ratio of the reference month spot fuel price to the study month forward fuel price. To accomplish this adjustment, the ratio of forward prices for the study month to the spot fuel prices for the reference month is used as a scaling factor. If the forward price for the study month was $7.08 and the spot fuel price from the reference month was $6.75, then the ratio is 1.05. The offers of generation units are then adjusted by this scaling factor. The price of fuel typically represents 80 to 90 percent of a generator's offer with the remainder being variable operations and maintenance costs. Where generators offer multiple points on a curve, each point on the curve is adjusted in this manner. The offers are then combined to create daily supply curves for each day in the period. The daily curves are then averaged to form an average supply curve for the study month. PJM then uses a non-linear least squares estimation technique to determine an equation that approximates and smooths this average supply curve. The NBT threshold price is the price at the point where the price elasticity of supply is equal to 1.0 for this estimated supply curve equation.[122] PJM publishes the details of the equation and parameters each month along with the NBT results.

122 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 136 (October 1, 2025)

The NBT test is a crude tool that is not based in market logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate real-time or day-ahead prices. In addition, it is a single threshold price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location and regardless of locational prices.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness nor does it require a payment from PJM markets.

When the zonal LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full zonal LMP. When the zonal LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions.[123]

Table 6-42 shows the NBT threshold price for the historical test from August 2010 through July 2011, and April 2012, when FERC Order No. 745 was implemented in PJM, through September 2025. The historical test was used as justification for the method of calculating the NBT for future months. From 2012 through 2021, the NBT threshold price exceeded the lowest historical test result of $34.07 per MWh one time, in March 2014 when the NBT threshold price was $34.93. The NBT threshold price exceeded the lowest historical test result of $34.07 per MWh in 10 of 12 months of 2022. In the first nine months of 2025, the NBT threshold price did not exceed the lowest historical test result of $34.07 per MWh.

Table 6-42 Net benefits test threshold prices: August 2010 through September 2025

	Historical Test ($/MWh)		Net Benefits Test Threshold Price ($/MWh)													
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jan	$42.03	$42.03		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44	$20.04	$18.11	$26.93	$40.25	$20.53	$24.35
Feb	$41.48	$40.49		$26.27		$26.52	$26.71	$31.57	$24.65	$23.49	$19.29	$18.70	$34.59	$29.79	$22.28	$25.94
Mar	$38.36	$38.48	$28.43	$24.73	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15	$17.44	$20.82	$30.00	$23.75	$18.70	$25.63
Apr	$38.07	$36.76	$27.92	$27.94	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36	$15.91	$23.47	$35.14	$23.68	$17.17	$30.31
May	$35.82	$34.68	$23.46	$27.73	$32.08	$23.71	$20.69	$29.65	$25.52	$21.01	$14.69	$21.40	$42.94	$23.43	$16.82	$27.76
Jun	$36.12	$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20	$15.56	$22.35	$44.29	$22.33	$18.41	$22.48
Jul	$37.68	$27.92	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76	$14.66	$21.59	$48.67	$22.66	$21.15	$25.54
Aug	$35.57	$33.86	$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57	$14.58	$20.52	$44.08	$24.89	$17.48	$25.38
Sep	$34.07	$31.07	$24.33	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19	$15.16	$23.06	$55.39	$25.04	$14.71	$20.92
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24	$55.97	$21.73	$14.22	
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35	$29.20	$49.57	$23.12	$19.81	
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47	$32.85	$42.75	$24.43	$20.13	
Average	$37.60	$35.60	$25.30	$28.10	$30.95	$23.96	$23.99	$27.33	$24.54	$21.64	$16.87	$23.03	$42.53	$25.42	$18.45	$25.37

123 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.4, Rev. 136 (October 1, 2025)

Table 6-43 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price.[124] In the first nine months of 2025, the highest zonal LMP in PJM was higher than the NBT threshold price 6,107 hours out of 6,551 hours, or 93.2 percent of all hours. Reductions occurred in 5,166 hours, 84.6 percent, of those 6,107 hours in the first nine months of 2025. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2024, through September 30, 2025. There are no economic payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reported reductions occurred in none of the hours in which LMP was below the NBT threshold price in the first nine months of 2024, and none of the hours in which LMP was below the NBT threshold price in the first nine months of 2025.

Table 6-43 Hours with price higher than NBT and economic load response occurrences in those hours: January 2024 through September 2025

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	2024	2025	2024	2025	Percent Change	2024	2025	Percentage Change
Jan	744	744	732	737	0.7%	51.6%	97.4%	45.8%
Feb	696	672	568	672	18.3%	31.5%	95.5%	64.0%
Mar	743	743	618	742	20.1%	27.7%	97.7%	70.0%
Apr	720	720	700	662	(5.4%)	37.0%	94.7%	57.7%
May	744	744	723	580	(19.8%)	64.3%	82.4%	18.1%
Jun	720	720	610	685	12.3%	65.9%	77.2%	11.3%
Jul	744	744	636	718	12.9%	87.6%	91.8%	4.2%
Aug	744	744	670	603	(10.0%)	85.4%	78.4%	(6.9%)
Sep	720	720	694	708	2.0%	81.7%	44.5%	(37.2%)
Oct	744		744			96.8%		
Nov	721		669			92.5%		
Dec	744		728			87.5%		
Total	8,784	6,551	8,092	6,107	(24.5%)	68.3%	84.6%	16.3%

124 The MWh for demand resources were downloaded as of October 14, 2025, and may change as a result of continued PJM billing updates.

Energy Efficiency

Energy Efficiency Resources (EE) are not capacity resources and do not contribute to reliability. FERC ruled on November 5, 2024, that EE should no longer be paid the capacity market clearing price effective with the 2026/2027 Delivery Year.[125] Payments from PJM customers to energy efficiency providers are a subsidy and uplift. The rules described here remain in effect until June 1, 2026.

The MMU had long recommended that Energy Efficiency Resources (EE) be removed from the capacity market mechanism because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[126] EE should not be part of the capacity market mechanism in any way. EE is appropriately and automatically compensated through the markets because to the extent that it actually reduces energy and capacity use, it reduces customer payments for energy and capacity. EE is appropriately incorporated in PJM forecasts, so the original logic for the inclusion of EE in the capacity market is no longer correct.

History

EE is not a capacity resource and is not treated as a capacity resource in the capacity market. EE does not contribute to meeting the RPM Reliability Requirement. EE resources may not serve as a replacement for the commitment of any other RPM Capacity Resource type.

On March 26, 2009, FERC approved Tariff and RAA changes to allow EE Resources to participate in PJM Capacity Markets beginning with the Base Residual Auction conducted in May 2009 which committed capacity for the 2012/2013 Delivery Year.[127] FERC approved PJM's request to allow EE Resource participation beginning June 1, 2011, in the remaining 2011/2012 Incremental Auctions by letter order dated January 22, 2010 in Docket No. ER10-366-000. The only reason that EE was included in the capacity market in the first place was that EE was asserted to not be included in the PJM load forecast used in

125 See 189 FERC ¶ 61,095, *reh'g denied*, 190 FERC ¶ 62,005 (2025).
126 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 37 (Dec. 18, 2024).
127 126 FERC ¶ 61,275 (2009)

the capacity market. PJM stated that EE was not fully reflected in the load forecast for four years based on the method in place at the time.

Revisions to the PJM load forecast to incorporate energy efficiency were endorsed at the November 19, 2015, MRC.[128] These revisions included improvements to comprehensively capture energy efficiency impacts through incorporation of projections from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO). The AEO forecast is based on a set of end use models for the residential, commercial, and industrial sectors. EIA accounts for state and utility efficiency programs by mapping regional EE program expenditures to end uses and tracks the number of units sold and associated efficiency information on an ongoing basis.[129]

As soon as PJM explicitly included EE in the load forecast used in the capacity market, PJM should have followed its tariff language and logic and eliminated EE from the capacity market construct entirely. Instead of eliminating EE from the capacity market construct consistent with the tariff and logic, PJM removed EE from capacity resource status and implemented a calculation method (misleadingly termed the addback method) that would pay EE the capacity market clearing price while having no impact, either price or quantity, on the capacity market. Beginning with capacity auctions conducted in 2016 for the 2016/2017 through 2025/2026 Delivery Years, PJM paid EE the capacity market clearing price while completely excluding EE from the actual capacity market. Use of this approach to EE addback did inappropriately require that customers pay for all EE offered at less than the market clearing price as an uplift payment or subsidy to EE sellers.

After the MMU filed a complaint in Docket No. EL24-126 requesting that the Commission require PJM to stop paying EE the uplift/subsidy, PJM filed to confirm removal of the EE from the capacity market construct, including the subsidy. On November 5, 2024, the Commission approved the complete removal of EE effective with the 2026/2027 capacity auction.[130] The MMU subsequently noticed withdrawal of the MMU complaint.[131]

Prior to the MMU complaint filed in Docket No. EL24-126, the MMU filed a complaint in Docket No. EL24-113 against indicated EE sellers for failure to submit post-installation M&V reports sufficient to support payments for EE from PJM for the 2024/2025 Delivery Year.[132] The complaint remains pending.

On May 29, 2025, in Docket No. EL25-87-000, the MMU filed a second complaint against indicated EE sellers who are providers of Energy Efficiency Resources for the 2025/2026 Delivery Year. The complaint alleges that the sellers' post-installation measurement and verification reports for the 2025/2026 Delivery Year are inadequate and capacity payments should be withheld pending further review.[133] The complaint remains pending.

PJM stakeholders initiated a holistic review of Energy Efficiency Resources participation in PJM markets in November of 2023. A sector-weighted super majority of PJM's stakeholders supported elimination of EE from the capacity construct at the MRC and the MC meetings on August 21, 2024.[134] PJM filed the proposal under Section 205 on September 6, 2024.[135] On November 5, 2024, the Commission issued an order approving the proposed Tariff and RAA revisions to remove Energy Efficiency Resource participation from the PJM capacity construct effective with the 2026/2027 Delivery Year.[136] On December 5, 2024, Affirmed Energy LLC filed a motion of a stay and a request for rehearing. An order denying rehearing by operation of law was issued January 6, 2025.[137] On February 7, 2025, the Commission issued an order denying the motion for stay and affirming its earlier denial of rehearing.[138]

On December 16, 2024, the Commission issued an Order to Show Cause and Notice of Proposed Penalty recommending civil penalties against American

128 See *Approved Minutes from the Markets and Reliability Committee*, <https://www.pjm.com/-/media/committees-groups/committees/mrc/20151217/20151217-item-01-draft-minutes-20151119.ashx> (December 17, 2015).
129 See EIA. Analysis of Energy Efficiency Program Impacts Based on Program Spending <https://www.eia.gov/analysis/studies/buildings/efficiencyimpacts/pdf/programspending.pdf> (Accessed January 18, 2024).
130 See 189 FERC ¶ 61,095, *reh'g denied*, 190 FERC ¶ 62,005 (2025).
131 See Complaint of the Independent Market Monitor for PJM, Docket No. EL24-126-000 (July 10, 2024), Notice of Withdrawal of Complaint, Docket No. EL24-126-000 (November 19. 2024); RAA Schedule 6 § L.1, OATT Attachment DD-1 § L.1.
132 See Complaint of the Independent Market Monitor for PJM, Docket No. EL24-113-000 (May 31, 2024).
133 See Complaint of the Independent Market Monitor for PJM, Docket No. EL25-87 (May 29, 2025).
134 PJM Transmittal Letter, Docket No. ER24-2995 at 41 (Sept. 6, 2024).
135 PJM Interconnection, L.L.C., Docket No. ER24-2995-000, Proposal to Enable Energy Efficiency to Benefit Loads Through Demand-Side Reduction to the Peak Load Forecast and Savings from Energy Market Charges (Sept. 6, 2024)
136 See 189 FERC ¶ 61,095.
137 See 190 FERC ¶ 62,005.
138 See 190 FERC ¶ 61,081.

Efficient, LLC, a large seller of EE, and its affiliates in connection with an alleged scheme to manipulate the capacity markets operated by PJM and MISO.[139] The Order directs American Efficient to show cause as to why it should not be required to pay a civil penalty of $722 million and disgorge $253 million in unjust profits. On January 29, 2025, American Efficient, et al. filed for review of the show cause order in the United States District Court for the Middle District of North Carolina.[140] The court case is pending.

EE Details

In addition to the fact that EE resources are not capacity resources, the measurement of EE that was required as a condition to receive subsidy payments from PJM were largely unsupported by factual evidence or actual measurements.

An EE Resource is required to be a project that involves the installation of more efficient devices or equipment, or the implementation of more efficient processes or systems, exceeding then current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of Schedule 6 (section L) of the Reliability Assurance Agreement. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site during the defined EE Performance Hours that is not reflected in the peak load forecast used for the auction delivery year for which the EE Resource is proposed.[141]

Despite the fact that the EE Resource must be fully implemented at all times during the delivery year, without any requirement of notice, dispatch, or operator intervention, EE accreditation is based only on extremely limited periods. EE is required to demonstrate savings only during three summer months and two winter months and only for extremely limited hours during those months. The EE Performance Hours in the summer are defined as the four hours from the hour ending 15:00 Eastern Prevailing Time (EPT) through the hour ending 18:00 EPT during all days for the three month period from June 1 through August 31, inclusive, of such delivery year, that is not a weekend or federal holiday. For the 2023/2024 Delivery Year, the summer EE Performance hours comprise 256 hours across 64 days. The EE Performance Hours in the winter are defined as the four hours from the hour ending 8:00 EPT and hour ending 9:00 EPT, and from the hour ending 19:00 EPT and hour ending 20:00 EPT during all days for the two month period from January 1 through February 28, inclusive, of such delivery year that is not a weekend or federal holiday, For the 2023/2024 Delivery Year, the winter EE Performance hours comprise 160 hours across 40 days. For the 2023/2024 Delivery Year, the total annual EE Performance hours comprised 416 hours across 104 days, or 4.7 percent of all hours in the year.

Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for actual capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator that is metered and tested. The Nominated MW for EE resources are not metered or measured or tested, although they could be, but are based on calculations of estimated savings based on a set of largely unverified and unverifiable assumptions. The Nominated Value of an EE Resource is the expected average demand reduction during the summer EE Performance Hours. Qualifying EE Resources must also have an expected average load reduction during the winter EE performance hours that is not less than the Nominated EE Value determine during the summer EE Performance Hours. If the Nominated EE Value determined during the summer EE Performance Hours is greater than the expected average demand during the winter performance hours, the expected demand during the winter performance hours will be the value of the EE Resource. The Nominated EE Value of a Summer-Period Energy Efficiency Resource is the expected average demand reduction during the summer EE Performance Hours.

139 See 189 FERC ¶ 61,196.

140 See American Efficient, LLC, et al. v. FERC, Case No. 1:25-cv-68.

141 See RAA Schedule 6 § L. Since 2010, the PJM tariff definition of "End User Customer" limits the scope of the term to mean only PJM Members. Letter Order, Docket No. ER11-1909-000 (December 20, 2010). Recently, PJM asserted that the reference in RAA Schedule 6 § L.1 and OATT Attachment DD-1 § L.1 to the defined term, "End Use Customer," was a mistake, and proposed to discontinue use of the defined term in the February 8, 2024, meeting of the PJM Governing Document Enhancement and Clarification Subcommittee (GDECS). The defined term was in place for more than 13 years and subject to many reviews. The proposed change removes the current requirement in the filed tariff that EE loads be End Use Customers and therefore be PJM Members. The proposed change is substantive and not a correction of a typographical error. PJM has been operating in violation of that tariff provision since 2010. The proposed change was filed and approved. *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER24-1987-000 (May 23, 2024).

Prescriptive energy efficiency MW are based on and paid on assumed savings calculated based on an assumed installation rate and on the difference between the assumed electricity usage of what is being replaced and the assumed electricity usage of the new product. All lighting EE is prescriptive. The majority of EE MW offered into the PJM Capacity Market are prescriptive energy efficiency MW. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement nor verification but instead relies on unverified assumptions and is too imprecise to rely on for the payment of more than $100 million per year. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods that are frequently significantly outdated.[142]

Most EE MW are not directly measured. Savings are calculated based on an assumed installation rate and assumed usage level, compared to the assumed electricity usage of the default. For example, the calculation of the summer period lighting savings for a residential lighting retrofit is generally:

$$\Delta kW = ((WattsBase - WattsEE) / 1000) * ISR * WHFd * CF$$

Where:

ISR = In Service Rate approximating percent of bulbs installed in calculation year

WHFd = Waste Heat Factor for Demand to account for cooling savings from efficient lighting

CF = Summer Peak Coincidence Factor approximating percent of EE Performance Hours device is in use

The inputs to these calculations are based on assumptions and observations over very limited periods and generally rely on data that is significantly out of date. Many EE Providers rely on usage assumptions from industry publications rather than from primary data collected from measurements of their own customers. A commonly referenced document in supporting Measurement & Verification reports is the Maryland/Mid-Atlantic Technical Reference Manual (TRM) facilitated and managed by Northeast Energy Efficiency Partnerships, a 501 (c)(3) non-profit organization funded by various advocacy groups and the federal government.[143] [144] While this manual focuses on a geographic region included in PJM's service territory, EE Providers can and do use assumptions based on installations in locations outside of PJM's service territory. The technical reference manuals (TRM) referenced by EE Providers are generally significantly outdated and therefore cannot reasonably be used to define the actual current baseline conditions that should be used for valuation of projects. Given the development cycle, the data underlying the TRM lags the publishing date by several years. Of TRMs frequently referenced by EE Providers, the Maryland/Mid-Atlantic TRM was published in 2020, the Pennsylvania TRM in 2024 and the Ohio TRM in 2019. The Pennsylvania PUC updates and approves its TRM on a 5-year cycle.[145] As a result, for the normal three year capacity market timing, a three year old TRM, relying on data from as much as five years prior to publication, is used to estimate savings for at least four years into the future. As a result, in the fourth year of the EE resource, its purported savings will be based on data from 15 years earlier. That is not a reasonable basis for calculating savings. Table 6-44 shows the current publishing dates of TRMs frequently referenced in M&V reporting submitted to PJM. In addition to Technical Reference Manuals, other studies and references are cited in EE M&V Plans and Reports. These citations are likewise used to justify the claimed benefits and savings attributed to Energy Efficiency projects. These materials, as with the TRMs, are often several years out of date and commonly 10 years old and in some cases older.

Table 6-44 Publishing dates (Year) of technical resource manuals

State/Region	Current Version
Delaware	2016
Illinois	2024
Maryland	2020
New Jersey	2023
Ohio	2019
Pennsylvania	2024
Tennessee	2015
Mid-Atlantic	2020

142 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 05 (Sep. 21, 2022).

143 See *Maryland/Mid-Atlantic Technical Reference Manual Version 10* <https://neep.org/mid-atlantic-technical-reference-manual-trm-v10> (May 27, 2020).

144 See *Northeast Energy Efficiency Partnership* <https://neep.org/> (March 4, 2024)

145 66 PA § 2806.1(c)(3)

Another weakness of the methods used to evaluate EE is the failure to recognize that the incremental benefits of EE measures decline over time as improved energy saving technology is adopted by customers. This improvement in technology reduces the baseline energy usage against which incremental savings should be measured. An example of a decreasing baseline in energy usage is in residential lighting. The assumed baseline condition was originally an incandescent bulb but should have evolved to more and more efficient LEDs, which eliminates the incremental savings when replaced by another LED lightbulb.

The mix of EE project types offered should have more quickly reflected the actual technology adopted in the markets. In the 2019/2020 BRA, lighting projects comprised 77 percent of all EE measures. Table 6-45 shows the composition of project types submitted in M&V Plans for the 2019/2020 RPM Base Residual Auction.

Table 6-45 EE Project Types – 2019/2020 Delivery Year

Project Type	2019/2020
Residential Lighting	23%
Residential HVAC	1%
Residential New Construction	<1%
Appliances	<1%
Commercial Lighting	54%
Commercial Prescriptive	8%
Commercial HVAC	<1%
Small Business	4%
Commercial Construction	2%
Other	7%

In the 2024/2025 BRA, lighting dropped to 45 percent of all EE measures. Building envelope measures, which include thermal performance improvements to exterior walls, windows, doors, and roofing to reduce building energy consumption were a growing project type encompassing 33 percent of all EE measures in the 2024/2025 BRA. Table 6-46 shows the composition of project types submitted in EE M&V Plans for the 2024/2025 RPM Base Residual Auction.

Table 6-46 EE Project Types – 2024/2025 Delivery Year

Project Type	2024/2025
Lighting	45%
Building Envelope	33%
Variable Frequency Drives	8%
Appliances	<1%
Other	14%

There is no evidence that the EE programs result in changed behavior or increases in savings. EE Providers may repackage the independent actions of customers that have already occurred. There is no evidence that EE participation in PJM markets causes End Use Customers to reduce their energy consumption beyond what they would have otherwise.

While EE does not affect the capacity market clearing price or quantity, customers do pay for EE at capacity market clearing prices. These direct payments to EE are a subsidy and uplift and an overpayment by customers. Table 6-47 shows the RPM revenues paid, by delivery year, to energy efficiency (EE) resources in PJM.

PJM does not codify eligibility requirements to claim the property rights to energy efficiency installations in the tariff. PJM does not have a registration system to track claims to property rights to energy efficiency installations and document installation periods of energy efficiency installations. The purpose of the registration system is to prevent duplicative claims to property rights and to document installation periods of energy efficiency to verify eligibility for continued participation measures. Energy Efficiency projects should be clearly identified by retail customer account, year of project installation and a description of the Energy Efficiency project.

A registration system would also serve the benefit of preventing multiple Energy Efficiency Providers from claiming property rights to the same project. The Energy Efficiency Resource Provider offering an Energy Efficiency Resource for payment must demonstrate to PJM that it has the legal authority to claim the demand associated with such Energy Efficiency Resource.[146] This demonstration is generally a prepackaged statement, provided by PJM, that

146 EE Post-Installation Measurement & Verification Report Template, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/post-installation-measurement-and-verification.ashx> (*Accessed Aug. 5, 2022*).

is never fully verified. PJM should have codified eligibility requirements to claim the property rights to Energy Efficiency installations in the Tariff. These eligibility requirements should specifically define the conditions under which an Energy Efficiency Resource Provider may claim the property rights to Energy Efficiency installations as well as evidentiary requirements such as signed contracts with their customers conferring such rights. PJM does not require contracts between the seller of EE to PJM and the actual owner of the EE. It is not always clear who the owner of the EE property rights actually is.

Table 6-47 shows the amount of energy efficiency (EE) resources paid as of June 1 for the 2011/2012 through 2025/2026 Delivery Years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[147] Only Kentucky has been so authorized by the Commission.[148] The total MW of energy efficiency resources paid decreased by 80.6 percent, from 7,716.0 MW in the 2024/2025 Delivery Year to 1,493.2 MW in the 2025/2026 Delivery Year.

Table 6-47 Energy efficiency resources (MW): 2011/2012 through 2025/2026 Delivery Years

Delivery Year	EE Paid (MW)	Total RPM Cleared (UCAP MW)	EE MW/ Capacity MW	EE Revenue
2011/2012	76.4	134,182.6	0.1%	$139,812
2012/2013	666.1	141,295.6	0.5%	$11,408,552
2013/2014	904.2	159,844.5	0.6%	$21,598,174
2014/2015	1,077.7	161,214.4	0.7%	$42,308,549
2015/2016	1,189.6	173,845.5	0.7%	$66,652,986
2016/2017	1,723.2	179,773.6	1.0%	$68,709,670
2017/2018	1,922.3	180,590.5	1.1%	$86,147,605
2018/2019	2,296.3	175,996.0	1.3%	$103,105,796
2019/2020	2,528.5	177,064.2	1.4%	$92,569,666
2020/2021	3,569.5	174,023.8	2.1%	$101,348,169
2021/2022	4,806.2	174,713.0	2.8%	$185,755,803
2022/2023	5,734.8	150,465.2	3.8%	$135,265,303
2023/2024	5,896.4	150,143.9	3.9%	$93,603,058
2024/2025	7,716.0	154,362.5	5.0%	$130,780,274
2025/2026	1,493.2	137,733.6	1.1%	$147,950,487

147 See 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).
148 FERC made an exception for Kentucky when it determined that RERRAs must obtain FERC approval prior to excluding EE. FERC explained that "the Commission accepted such condition at the time the Kentucky Commission approved the integration of Kentucky Power into PJM." 161 FERC ¶ 61,245 at P 66 (2017).

Table 6-48 shows the total revenues to energy efficiency based on the zone in which they are located, as of June 1 for the 2024/2025 and 2025/2026 Delivery Years.

Table 6-48 Energy efficiency resource revenue by zone: 2024/2025 and 2025/2026 Delivery Years

	Revenue		Percent of EE Revenue	
Zone	2024/2025	2025/2026	2024/2025	2025/2026
AECO	$2,900,594	$1,582,433	2.2%	1.1%
AEP	$8,311,932	$11,932,785	6.4%	8.1%
APS	$4,019,526	$6,215,064	3.1%	4.2%
ATSI	$6,165,467	$6,155,174	4.7%	4.2%
BGE	$10,563,637	$12,102,754	8.1%	8.2%
COMED	$10,328,888	$28,316,443	7.9%	19.1%
DAY	$1,347,504	$1,607,671	1.0%	1.1%
DEOK	$6,482,315	$2,174,691	5.0%	1.5%
DOM	$9,388,297	$23,822,243	7.2%	16.1%
DPL	$17,479,123	$3,006,666	13.4%	2.0%
DUQ	$1,385,670	$1,750,387	1.1%	1.2%
JCPL	$6,373,282	$5,762,243	4.9%	3.9%
METED	$2,834,056	$2,096,549	2.2%	1.4%
PECO	$11,209,242	$12,335,236	8.6%	8.3%
PENELEC	$2,556,322	$1,699,550	2.0%	1.1%
PEPCO	$7,075,048	$7,305,169	5.4%	4.9%
PPL	$6,910,670	$4,155,526	5.3%	2.8%
PSEG	$15,386,096	$15,713,157	11.8%	10.6%
RECO	$62,605	$216,746	0.0%	0.1%
Total	$130,780,274	$147,950,487	100.0%	100.0%

As defined in the RAA, each LSE incurs a Locational Reliability Charge, subject to certain offsets and other adjustments as described in Attachment DD, Sections 5.14B through 5.14E and Section 5.15.[149] Locational Reliability Charges are equal to the LSE's Daily Unforced Capacity Obligation in a zone during the Delivery Year multiplied by the applicable Final Zonal Capacity Price in the zone. The Tariff does not define the allocation of EE revenue requirements to load in RPM. In practice, PJM allocates total EE revenue requirements to load prorata based on final zonal UCAP obligations. As a result, the allocation of EE costs to zones is not equal to the revenue requirement of EE resources located in that zone. Zones in which no EE resources are located are allocated a share of total EE revenue requirements based on their share of

149 See PJM, Intra-PJM Tariffs, RAA, Article 7, §2.

the total PJM UCAP obligation. Table 6-49 and Table 6-50 shows the zonal revenue requirement of EE resources compared to the zonal allocation of total EE revenue requirements to load. Where a zone's load charge is greater than the revenue requirement of EE resources located in that zone, the zone's customers are subsidizing the revenue requirement of EE resources located in other zones. Where a zone's load charge is less than the revenue requirement of EE resources located in that zone, the zone's customers are receiving a subsidy from customers located in other zones.

Table 6-49 Energy efficiency zonal load charges and revenues: 2024/2025 Delivery Year

		2024/2025		
Zone	LDA	EE Load Charge	EE Revenue	EE Load Charge minus Revenue
AE	EMAAC	$2,535,754	$2,900,594	($364,840)
AEP	RTO	$12,137,414	$8,311,932	$3,825,482
APS	RTO	$9,366,104	$4,019,526	$5,346,578
ATSI	ATSI	$12,926,950	$6,165,467	$6,761,484
BGE	BGE	$6,731,078	$10,563,637	($3,832,559)
COMED	COMED	$20,323,799	$10,328,888	$9,994,911
DAYTON	DAY	$3,380,646	$1,347,504	$2,033,141
DEOK	DEOK	$4,577,737	$6,482,315	($1,904,578)
DLCO	RTO	$2,826,017	$1,385,670	$1,440,347
DOM	RTO	$3,898,695	$9,388,297	($5,489,602)
DPL	EMAAC	$3,998,938	$17,479,123	($13,480,185)
EKPC	RTO	$2,506,944	$0	$2,506,944
JCPL	EMAAC	$6,142,999	$6,373,282	($230,283)
METED	MAAC	$3,147,572	$2,834,056	$313,516
OVEC	RTO	$64,743	$0	$64,743
PECO	EMAAC	$8,743,496	$11,209,242	($2,465,746)
PENLC	MAAC	$2,958,739	$2,556,322	$402,417
PEPCO	PEPCO	$6,244,429	$7,075,048	($830,619)
PL	PPL	$7,575,970	$6,910,670	$665,299
PS	PSEG	$10,273,581	$15,386,096	($5,112,515)
RECO	EMAAC	$418,669	$62,605	$356,064
Total		$130,780,274	$130,780,274	($0)

Table 6-50 Energy efficiency zonal load charges and revenues: 2025/2026 Delivery Year

		2025/2026		
Zone	LDA	EE Load Charge	EE Revenue	EE Load Charge minus Revenue
AE	EMAAC	$2,449,029	$1,582,433	$866,596
AEP	RTO	$12,592,507	$11,932,785	$659,722
APS	RTO	$8,893,789	$6,215,064	$2,678,725
ATSI	ATSI	$12,837,721	$6,155,174	$6,682,547
BGE	BGE	$6,537,997	$12,102,754	($5,564,757)
COMED	COMED	$19,777,674	$28,316,443	($8,538,770)
DAYTON	DAY	$3,275,732	$1,607,671	$1,668,062
DEOK	DEOK	$4,429,801	$2,174,691	$2,255,110
DLCO	RTO	$2,720,453	$1,750,387	$970,066
DOM	DOM	$23,482,297	$23,822,243	($339,946)
DPL	EMAAC	$3,905,601	$3,006,666	$898,935
EKPC	RTO	$2,459,803	$0	$2,459,803
JCPL	EMAAC	$5,953,711	$5,762,243	$191,468
METED	MAAC	$3,098,582	$2,096,549	$1,002,033
OVEC	RTO	$62,158	$0	$62,158
PECO	EMAAC	$8,436,927	$12,335,236	($3,898,309)
PENLC	MAAC	$2,900,712	$1,699,550	$1,201,161
PEPCO	PEPCO	$6,047,984	$7,305,169	($1,257,185)
PL	PPL	$7,516,987	$4,155,526	$3,361,461
PS	PSEG	$10,165,958	$15,713,157	($5,547,199)
RECO	EMAAC	$405,064	$216,746	$188,318
Total		$147,950,487	$147,950,487	($0)

The ownership of Energy Efficiency is highly concentrated. The combined market share of the four largest companies ranges from 90 to 99 percent of all paid Energy Efficiency MW. The HHI for Energy Efficiency resources shows that ownership of EE for the entire market is highly concentrated for each of the last six delivery years. Table 6-51 shows the HHI value for paid Energy Efficiency MW and the market share of the four largest suppliers by delivery year for the entire market.

Table 6-51 Energy Efficiency HHI: 2019/2020 through 2025/2026

Delivery Year	HHI	Structure	Top 4 Market Share
2019/2020	3574	Highly Concentrated	90.6%
2020/2021	3005	Highly Concentrated	89.8%
2021/2022	3409	Highly Concentrated	91.6%
2022/2023	5803	Highly Concentrated	99.1%
2023/2024	6029	Highly Concentrated	99.9%
2024/2025	5749	Highly Concentrated	98.0%
2025/2026	2804	Highly Concentrated	96.0%

The ownership of Energy Efficiency is also highly concentrated on an LDA basis as shown by the HHI levels. The individual LDA HHI values cannot be made public based on PJM's confidentiality rules. Table 6-52 shows the HHI value for paid MW by LDA for the 2024/2025 and 2025/2026 Delivery Years.

Table 6-52 Energy Efficiency HHI by LDA

	Structure	
LDA	2024/2025	2025/2026
ATSI	Highly Concentrated	Highly Concentrated
ATSI-CLEVELAND	Highly Concentrated	Highly Concentrated
BGE	Highly Concentrated	Highly Concentrated
COMED	Highly Concentrated	Highly Concentrated
DAY	Highly Concentrated	Highly Concentrated
DEOK	Highly Concentrated	Highly Concentrated
DOM	Not a Modeled LDA	Highly Concentrated
DPL-SOUTH	Highly Concentrated	Highly Concentrated
EMAAC	Highly Concentrated	Highly Concentrated
MAAC	Highly Concentrated	Highly Concentrated
PEPCO	Highly Concentrated	Highly Concentrated
PPL	Highly Concentrated	Highly Concentrated
PS-NORTH	Highly Concentrated	Highly Concentrated
PSEG	Highly Concentrated	Highly Concentrated
RTO	Highly Concentrated	Highly Concentrated

Table 6-53 shows how EE MW are distributed across LDAs. For example, 22.6 percent of all EE MW were in COMED in the 2025/2026 Delivery Year.

Table 6-53 Energy Efficiency Share by LDA

	Percent of EE	
LDA	2024/2025	2025/2026
ATSI	6.9%	4.2%
ATSI-CLEVELAND	0.7%	0.4%
BGE	5.0%	5.0%
COMED	13.8%	22.6%
DAY	1.7%	1.2%
DEOK	2.4%	1.7%
DPL-SOUTH	1.3%	10.3%
EMAAC	15.1%	1.6%
MAAC	3.9%	15.1%
PEPCO	5.2%	2.7%
PPL	5.1%	5.4%
PS-NORTH	5.1%	3.1%
PSEG	5.3%	6.7%
RTO	28.6%	5.6%

Peak Shaving Adjustment

Peak Shaving Adjustment (PSA) provides an alternative means for demand response to participate in the Reliability Pricing Model (RPM). Rather than being on the supply side of the capacity market, a PSA participates on the demand side through a modified peak load forecast for the zone in which the Peak Shaving Adjustment resources are located. The peak shaving adjusted load forecast is included in the VRR curve. An important issue is that the resultant reduction in capacity obligation is socialized across all loads in the zone rather than directly benefitting the resources providing the Peak Shaving Adjustment.[150] This eliminates the incentive for individual customers to participate in peak shaving. The solution is a retail rate design that directly assigns the benefits of peak shaving to individual customers. The retail rate design is within the authority of state regulators and not the authority of FERC which has jurisdiction over the wholesale markets.

A PSA plan must include: the basis for the planned reductions; a THI trigger for interruption; the duration of the interruption in hours; the MW value of the curtailment; the months of the offer; all historical addbacks for the nominated programs.[151] Any resource selling a PSA must reduce load on any day in which its trigger is met or exceeded. The trigger is based on the actual maximum daily temperature humidity index (THI) for the relevant PJM zone. When the trigger is met, the PSA must comply with its defined offer parameters including number of hours of interruption. Failure to operate to these parameters will lead to a reduction in the peak shaving adjustment value in future delivery years. Performance is measured based on the aggregated Customer Baseline (CBL). PJM applies a three year rolling average of the annual peak shaving performance ratings to the program's total participating MW in order to determine its peak shaving adjustment.

150 See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).
151 "PJM Manual 19: Load Forecasting and Analysis," Attachment D, Rev. 37 (Dec. 18, 2024).

Distributed Energy Resources

Distributed Energy Resources (DER) include generation connected to distribution level facilities, behind the meter generation, and energy storage facilities connected to the distribution grid or to load. FERC issued Order No. 2222 on September 17, 2020, with the goal of removing barriers for small distributed resources to enter the wholesale market by allowing them to aggregate in order to encourage competition, but larger resources, up to 5 MW, can participate.[152] On May 1, 2025, FERC issued an order accepting all of the final elements of PJM's compliance filing including delaying the effective date for the DER Aggregation Participation Model to February 2, 2028. PJM is currently developing implementation details for DER Aggregation Resources (DERAs) at the Distributed Resources Subcommittee (DISRS).

PJM proposed Manual 18 updates for Planned DER Capacity Resource's participation in the 2028/2029 BRA.[153] The changes include detailed business rules for DER Capacity Aggregation Resources, DER plan requirements, RPM commitment compliance, and test failure charges. All DER will be planned resources for the 2028/2029 auction, meaning PJM will not require the CSP to register an actual physical resource prior to the auction. The MMU identified a loophole in the market power mitigation rules applicable to planned DER in PJM's proposed Manual 18 language. The loophole exists because a DER aggregation can change resource types between the time of clearing in an auction and the actual delivery year. For example, a DER aggregation can offer as a homogeneous demand resource and then change to a heterogeneous DER resource in the actual delivery year. This would allow a DER aggregation to avoid market power mitigation rules in the capacity market. Under the proposed rules, if a planned DER Capacity Aggregation Resource consists of only demand response resources (homogeneous DR), it is exempt from the market power mitigation rules. Planned resources can change types between BRAs and IAs, or between capacity auctions and delivery years. The rules allow a planned DER Capacity Aggregation Resource solely comprised of demand response resources that was not subject to market power mitigation rules in a capacity auction to add generation after the auction. This would allow the added generation to avoid market power mitigation rules. This loophole should be closed with a simple rule change to prevent the behavior.

The MMU recommends that DER aggregations that clear in a capacity auction not be permitted to change status from homogeneous demand response to any other status for any additional auctions for the same delivery year, or for the delivery year.

Getting the rules right at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undermines the efficiency and competitiveness of the power markets. In addition, getting the implementation details right is critical in keeping the original intention of Order No. 2222 to enhance competition in wholesale markets while removing barriers for small distributed resources. To date, PJM is not meeting these objectives.

Nodal Aggregation and Size

The PJM market is a nodal market. Nodal markets provide efficient price signals to resources in an economically dispatched, security constrained market. Aggregation behind a single node is feasible, is consistent with the nodal market principle, and will encourage competition. The accepted DER Aggregation Participation Model allows multinodal aggregation for small resources that satisfy a few conditions. Energy injection from DERs across multiple nodes, even if it is small, will change congestion patterns that PJM would not have the ability to predict and control. Allowing DER aggregation across nodes even for small resources is not necessary and would distort the nodal market signals that indicate where capacity and energy are needed and their impacts on congestion. The MMU recommends that PJM use a nodal approach for DER participation in PJM markets that excludes multinodal aggregation.

The accepted DER Aggregation Participation Model does not propose a maximum size requirement for DER Aggregation Resources. This loophole would allow larger DERs to divide one larger resource into multiple DERs less than 5 MW and register them as one DER Aggregation Resource, undermining the intent of the DER approach. To avoid this loophole, there

152 See 172 FERC ¶ 61,247 at PP 6–7.
153 See "Manual 18 Revisions - Redline," from the October 9, 2025 meeting of the MIC <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20251009/20251009-item-01-1---manual-18-revisions---redline.pdf>.

should be a maximum size requirement on DER Aggregation Resources. The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations.

EDC Role

The EDCs' dual role as the distribution system operator and as a DER Aggregator is a threat to PJM's competitive market. When an EDC, acting in its proposed role as a market participant, controls its competitors' access to the market, the result is not structurally competitive. The result would be to create barriers to competition, exactly the opposite of FERC's intent. EDCs have a very significant role to play as designers, builders and managers of the local grids, without competing with DER providers. The accepted DER Aggregation Participation Model does not prevent EDCs from serving as DER aggregators or address the market power issues, based on a reference to the provision of Order No. 2222 that prohibits RTOs/ISOs from limiting the business models under which DER aggregators can operate. FERC, however, stated that it could revisit the EDCs' role in the PJM markets, if "evidence of undue discrimination regarding the participation of DER aggregations in RTO/ISO markets" is discovered.[154] The MMU continues to recommend that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role.

Cases where EDCs override PJM dispatch instructions should be communicated to PJM and recorded in the PJM market systems for operations and market monitoring purposes. When DER Aggregation Resources update bidding parameters due to override instructions from the EDC, the MMU should be able to check whether the update is due to an override or other operational or economic reasons. When the EDC itself is the DER Aggregator and it overrides its PJM dispatch instruction, it should also be communicated to PJM and recorded. FERC clarified that if an EDC's override actions are discriminatory or involve the exercise of market power such behavior would violate the terms of PJM's tariff and that such actions can be monitored and addressed through existing mechanisms such as Attachment M.[155] However, the proposed tariff language does not explicitly define the MMU's role in monitoring or mitigating the potential exercise of market power by EDCs. To enable efficient and effective market monitoring, EDCs and DERAs should be explicitly required to provide information requested by the MMU. The MMU recommends that the Commission require PJM to include in OATT Attachment M a statement explicitly affirming that the Market Monitor's role includes the right to collect information from EDCs and DERA related to actions taken on the distribution system related to DER Aggregation Resources.

Net Metering Resources

A net metering resource is a single electric customer location that has both generation and load, where the generation can exceed the load, and the customer pays for energy or receives compensation for energy based on the net energy output measured at the customer meter. Retail customers on a net metering tariff with their distribution utility pay the retail rate when consuming and are paid the retail rate when selling energy. These resources cannot participate in the energy or capacity markets, because they already receive full compensation for their output. That retail rate compensation includes credits for ancillary services charges.

According to PJM, no net metering resources in the PJM footprint provide ancillary services as part of a retail program.[156] From PJM's perspective, this means all net metering resources in its territory are eligible to participate in its ancillary services market.[157] PJM argues that even if a resource is compensated for the same service at the retail and the wholesale level, it should not be considered double counting. Under this proposal, a net metered resource that receives credits through its retail rate for reducing its ancillary services purchase can also receive payment from PJM for providing the same ancillary services. That is clearly double counting. The accepted DER Aggregation Participation Model allows EDCs to raise concerns about double counting but neither PJM nor an EDC may preclude a Component DER from providing ancillary services based on the resources being compensated for ancillary services at the retail level. No resource should be paid more than once for its services. If the net energy metering resources receive credits at a rate that includes compensation for ancillary services, that means they are providing

154 182 FERC ¶ 61,143 at P 334.
155 See 188 FERC ¶ 61,076 at P169.
156 See Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022) at 41.
157 FERC Docket No. ER22-962-005 at 15.

the service and being compensated for it. The MMU recommends that net metering resources be prohibited from participating in wholesale ancillary services markets if they are compensated for the service at the retail level.

Outside the Order No. 2222 rule development, a proposal was developed and approved by PJM stakeholders to allow DERs at net metering sites to be able to inject in the regulation market before February 2, 2028, when the DER Aggregation Participation Model will be effective.[158] This selective implementation of a part of a rule set is unjust and unreasonable. There is no reason to implement a small part of a participation model earlier than the FERC approved effective date, especially, if the expected result is to change the definition of demand response resources and enable them to inject in the regulation market. The MMU opposed the proposal.

158 See "DER Regulation Market Only Participation at NEM Customer Sites," from the October 23, 2025 meeting of the MC <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20251023/20251023-consent-agenda-b---1-der-regulation-market-only-participation-at-nem-customer-sites---presentation.pdf>.

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the analysis includes the theoretical new entrant net revenues for combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear, solar, and wind generating units.

Overview

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices, gas prices and coal prices increased in the first nine months of 2025 compared to the first nine months of 2024. The net effects were that in the first nine months of 2025, average energy market theoretical net revenues increased by 30 percent for a new combustion turbine (CT), increased by 35 percent for a new combined cycle (CC), increased by 148 percent for a new coal plant (CP), increased by 46 percent for a new nuclear plant, increased by 279 percent for a new diesel (DS), increased by 52 percent for a new onshore wind installation, increased by 49 percent for a new offshore wind installation and increased by 42 percent for a new solar installation.
- The price of natural gas and coal increased in the first nine months of 2025. The marginal costs of a new CT were greater than the marginal cost of a new CP only in January, February and March 2025. The marginal costs of a new CC were greater than the marginal cost of a new CP only in January 2025.
- In the first nine months of 2025, spark spreads and dark spreads and the volatility of spark spreads and dark spreads increased in BGE, COMED and Western Hub compared to the first nine months of 2024. In the first nine months of 2025, spark spreads decreased while dark spreads and the volatility of both spark spreads and dark spreads increased in PSEG compared to the first nine months of 2024.
- Of the 16 PJM nuclear plants analyzed, all are expected to cover their avoidable costs from energy and capacity market revenues in 2025, 2026 and 2027, without any subsidies.

Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical revenues that are scaled based on forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals alone has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs. A basic purpose of the capacity market is to allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market.

PJM's introduction of a form of ELCC for defining available capacity has made the definition of reliability less clear. The ELCC derate factors are volatile and subject to changes for reasons that are not clear to generation owners or other market participants. There are significant issues with PJM's implementation of its approach to ELCC.

Net Revenue

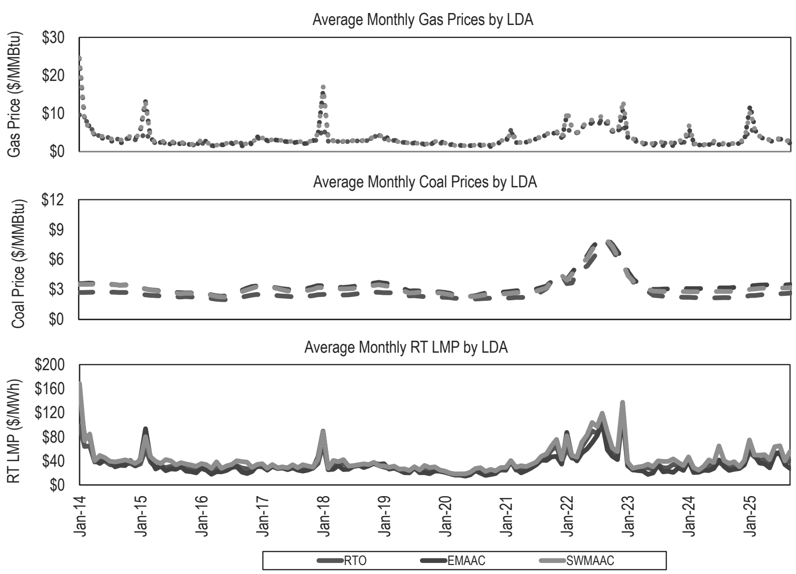
When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets, including uplift payments, and from the provision of black start and reactive services and capability, and from subsidies like RECs, less the short run marginal costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue. Net revenue is the contribution to fixed costs, which include a return on investment, depreciation and income taxes, and to avoidable costs, which include long term and intermediate term operation and maintenance expenses.[1] Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service markets, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity and to encourage maintaining existing capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets. The current definition of net revenue is not fully accurate as the FERC ordered definition uses price-based offers at times and does not include revenue from opportunity cost adders for environmentally constrained resources.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP in the first nine months of 2025 increased 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh. Gas prices and coal prices increased in the first nine months of 2025 compared to the first nine months of 2024. The price of eastern natural gas was 83.4 percent higher, the price of western natural gas was 59.2 percent higher; the price of Northern Appalachian coal was 11.4 percent higher; the price of Central Appalachian coal was 7.8 percent higher; and the price of Powder River Basin coal was 2.5 percent higher (Figure 7-1). The price of ULSD NY Harbor Barge (ultra low sulfur diesel) was 6.4 percent lower in the first nine months of 2025 than in the first nine months of 2024.

1 Avoidable costs are sometimes referred to as going forward costs.

Figure 7-1 Energy market net revenue factor trends: 2014 through September 2025



Spark Spreads and Dark Spreads

The spark or dark spread is defined as the difference between the LMP received for selling power and the cost of fuel used to generate power, converted to a cost per MWh. The spark spread compares power prices to the cost of gas and the dark spread compares power prices to the cost of coal. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

In the first nine months of 2025, spark spreads and dark spreads and the volatility of spark spreads and dark spreads increased in BGE, COMED and Western Hub compared to the first nine months of 2024. In the first nine months of 2025, spark spreads decreased while dark spreads and the volatility of both spark spreads and dark spreads increased in PSEG compared to the first nine months of 2024.

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviations.

Table 7-1 Peak hour spark and dark spreads ($/MWh)

	BGE		COMED		PSEG		Western Hub	
Jan-Sep	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2024	$36.35	$24.84	$18.96	$13.59	$18.12	$0.94	$26.32	$15.15
2025	$44.29	$37.38	$24.07	$26.88	$18.85	$15.88	$32.74	$26.72
Percent change	22%	50%	27%	98%	4%	1,584%	24%	76%

Table 7-2 Peak hour spark and dark spread standard deviation ($/MWh)

	BGE		COMED		PSEG		Western Hub	
Jan-Sep	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2024	$57.2	$57.2	$27.6	$27.3	$28.9	$29.4	$33.8	$33.4
2025	$89.7	$91.1	$63.2	$63.4	$92.0	$74.9	$78.1	$75.1
Percent change	57%	59%	129%	133%	218%	154%	131%	125%

Figure 7-2 shows the hourly spark spread for peak hours for BGE, COMED, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2021 through September 2025[2]

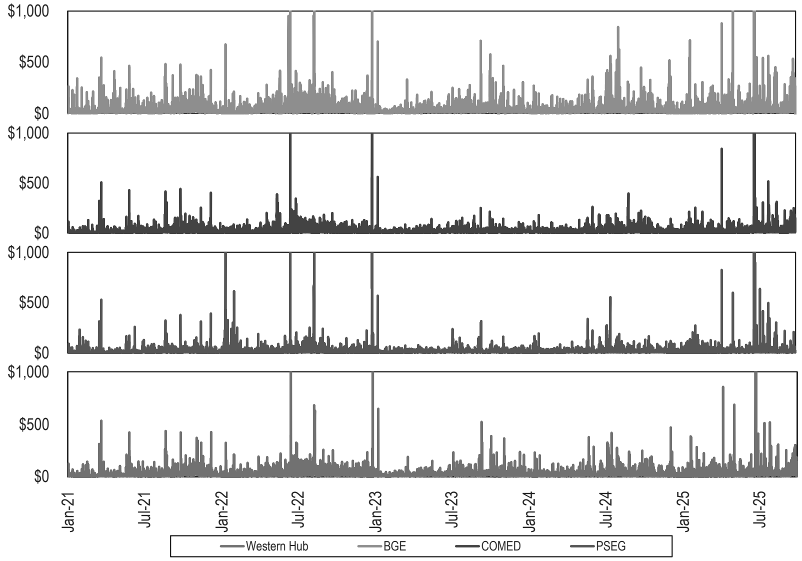
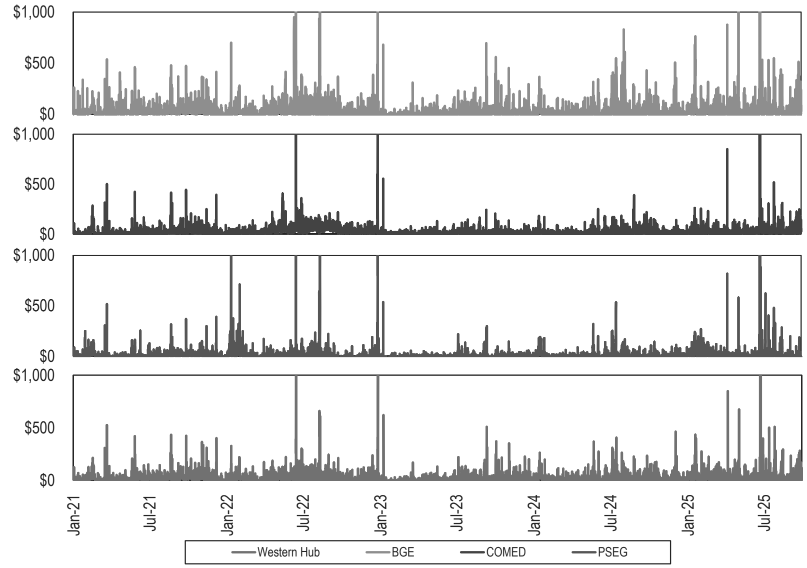


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2021 through September 2025[3]



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new unit's operations and potential net revenue in PJM markets.

Analysis of energy market net revenues for a new unit includes eight power plant configurations:

- The CT plant is a single GE Frame 7HA.03 CT with an installed capacity of 409.3 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction, and dual fuel capability.

2 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for COMED, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

3 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, daily coal prices, and average transportation costs by coal type; Powder River Basin coal for COMED, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

- The CC plant includes two single shaft 1x1 GE Frame 7HA.02 CTs, each with a single combustion turbine, heat recovery steam generator, and steam turbine with a total installed capacity of 1,362 MW, equipped with SCR for NO_x reduction, dry cooling, duct burners, and dual fuel capability.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a baghouse for particulate control.
- The DS plant is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 104 Siemens 2.9 MW wind turbines with an installed capacity of 301.6 MW.
- The offshore wind installation includes of 40 Siemens 10.0 MW wind turbines with an installed capacity of 400.0 MW.
- The solar installation is a 472 acre ground mounted tracking solar farm with an installed AC capacity of 200 MW.
- The battery storage unit is a 2.5 MW, 10 hour battery capable of providing 2.5 MWh for 10 hours, or 25 MWh.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4] [5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.[6] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

4 Hourly ambient conditions supplied by DTN.
5 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
6 CO_2 emission allowance costs only included for states participating in RGGI.
7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[8]

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[9] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt month prices, adjusted for rail transportation costs.[11] Net revenues are calculated for all zones except OVEC.[12]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[13] [14] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

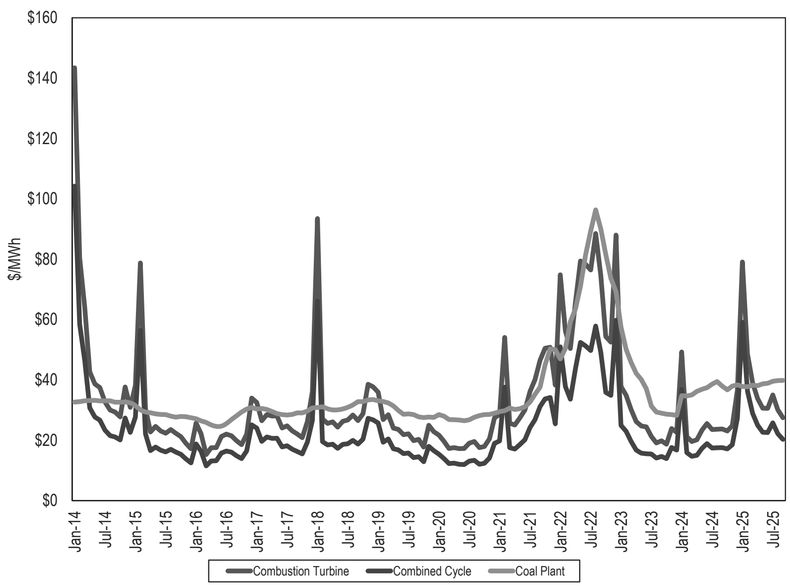
Table 7-3 Average short run marginal costs: January through September, 2025

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$39.36	9,241	$0.54
CC	$29.18	6,369	$0.88
CP	$38.72	9,250	$5.64
DS	$173.01	9,660	$0.25
Nuclear	$0.00	NA	$0.00
Wind	$0.00	NA	$0.00
Wind (off shore)	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

8 Outage figures obtained from the PJM eGADS database.
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be warm starts.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt month prices obtained from Platts.
12 The Ohio Valley Electric Corporation (OVEC) includes a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, but does not occupy a single geographic footprint like the other control zones.
13 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
14 VOM rates provided by Pasteris Energy, Inc.

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014 shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-4). The average monthly marginal costs of a new CC and CT were greater than the marginal cost of a new CP only in January 2025 and the average monthly marginal costs of a new CT were greater than the marginal cost of a new CP only in February and March 2025. Marginal costs are based on spot fuel costs. Individual generation plants may have contracts for coal that differ significantly from spot prices.

Figure 7-4 Average short run marginal costs: 2014 through September 2025



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

Gas prices, coal prices, and energy prices are reflected in new unit capacity factors. Table 7-4 shows the average capacity factor for new units. The capacity factors for a new CP increased in the first nine months of 2025 compared to the first nine months of 2024.

Table 7-4 Average capacity factor: January through September, 2014 through 2025

Jan-Sep	CT	CC	CP	DS	Nuclear	On Shore Wind	Solar
2014	48%	75%	62%	4%	91%	23%	17%
2015	63%	76%	57%	3%	92%	22%	19%
2016	71%	78%	48%	1%	91%	22%	17%
2017	53%	72%	40%	1%	93%	25%	19%
2018	58%	81%	42%	3%	94%	25%	18%
2019	51%	79%	24%	1%	92%	25%	19%
2020	50%	79%	11%	1%	93%	24%	18%
2021	40%	78%	39%	1%	93%	23%	18%
2022	40%	78%	35%	1%	92%	24%	19%
2023	54%	75%	19%	0%	93%	23%	17%
2024	60%	78%	32%	1%	92%	23%	21%
2025	54%	78%	44%	3%	92%	23%	21%

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least two hours, or any additional profitable hours bordering the profitable day-ahead or real-time block.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were higher in all zones in the first nine months of 2025 as a result of higher spark spreads (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through September, 2014 through 2025 (Dollars per installed MW-year)[15]

	Jan-Sep												
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Change in 2025 from 2024
ACEC	$73,405	$41,708	$46,249	$22,093	$26,654	$20,547	$5,743	$10,290	$31,629	$18,535	$22,775	$34,379	51%
AEP	$67,449	$54,923	$47,821	$26,232	$66,440	$32,619	$28,343	$34,229	$84,256	$47,744	$63,251	$84,886	34%
APS	$90,853	$86,337	$51,965	$31,277	$67,802	$17,863	$14,195	$23,621	$57,551	$45,600	$75,795	$108,112	43%
ATSI	$49,411	$47,866	$46,175	$27,588	$78,519	$33,933	$28,701	$33,750	$78,372	$43,461	$74,666	$86,789	16%
BGE	$88,636	$60,519	$79,045	$32,085	$47,455	$25,748	$22,946	$34,435	$93,840	$66,508	$81,071	$99,248	22%
COMED	$31,315	$25,079	$29,620	$17,939	$29,727	$18,371	$15,930	$22,137	$60,292	$33,158	$49,254	$62,073	26%
DAY	$44,343	$44,007	$44,581	$26,759	$74,664	$37,463	$32,823	$45,405	$93,162	$51,671	$81,197	$90,300	11%
DOM	$59,304	$51,218	$55,122	$27,695	$51,983	$27,191	$23,669	$39,286	$99,843	$51,255	$76,253	$133,038	74%
DPL	$58,747	$27,998	$24,357	$10,733	$21,770	$13,405	$8,166	$22,060	$52,631	$38,060	$47,113	$54,722	16%
DUKE	$40,531	$41,305	$42,521	$25,534	$82,843	$33,962	$29,196	$42,284	$87,770	$49,230	$74,294	$83,443	12%
DUQ	$39,013	$62,838	$61,651	$34,218	$50,815	$22,957	$24,168	$28,662	$68,985	$60,075	$69,715	$74,372	7%
EKPC	$59,896	$43,174	$41,526	$21,852	$50,179	$26,697	$24,964	$31,657	$75,449	$40,349	$52,308	$66,097	26%
JCPLC	$74,696	$40,861	$41,674	$25,592	$27,533	$19,586	$6,288	$9,372	$30,180	$18,366	$20,791	$33,508	61%
MEC	$72,367	$72,623	$61,579	$42,471	$38,978	$23,145	$25,643	$36,920	$96,323	$39,606	$55,479	$69,855	26%
PE	$121,487	$120,357	$76,585	$41,150	$75,603	$29,818	$31,263	$39,860	$90,900	$64,507	$86,071	$114,661	33%
PECO	$74,378	$71,310	$58,363	$33,913	$35,130	$18,652	$18,545	$19,682	$48,635	$25,171	$47,326	$52,423	11%
PEPCO	$64,618	$39,478	$40,681	$20,329	$38,778	$15,797	$11,062	$22,063	$51,285	$33,796	$52,863	$81,137	53%
PPL	$190,484	$139,459	$62,799	$38,323	$77,618	$21,159	$19,976	$35,373	$89,011	$42,353	$61,903	$74,866	21%
PSEG	$90,869	$83,039	$62,484	$39,212	$39,815	$20,785	$6,299	$13,134	$33,757	$18,587	$20,959	$33,210	58%
REC	$66,401	$46,358	$45,660	$26,864	$29,648	$20,669	$7,102	$21,483	$37,341	$23,561	$24,568	$42,283	72%
PJM	$58,381	$60,023	$51,023	$28,593	$50,598	$24,018	$19,251	$28,285	$68,061	$40,580	$56,883	$73,970	30%

15 The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.[16] The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CC plant energy market net revenues were higher in all zones in the first nine months of 2025 as a result of higher spark spreads (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through September, 2014 through 2025 (Dollars per installed MW-year)[17]

	Jan-Sep												
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Change in 2025 from 2024
ACEC	$107,700	$62,168	$56,886	$39,174	$50,966	$41,724	$22,926	$30,946	$59,195	$27,837	$31,478	$51,631	64%
AEP	$92,815	$77,655	$62,247	$44,434	$92,617	$56,774	$44,425	$61,016	$156,624	$76,251	$84,611	$116,473	38%
APS	$131,582	$118,635	$80,327	$54,564	$102,536	$48,260	$39,833	$59,701	$122,585	$67,327	$99,649	$139,850	40%
ATSI	$69,129	$71,026	$61,144	$45,061	$102,961	$57,830	$44,671	$61,626	$149,711	$71,671	$95,636	$118,866	24%
BGE	$133,129	$95,354	$106,523	$57,009	$83,020	$58,009	$50,680	$73,303	$158,802	$91,285	$102,418	$126,367	23%
COMED	$40,701	$41,928	$43,638	$30,194	$47,185	$35,931	$28,771	$40,983	$111,441	$54,086	$63,936	$82,827	30%
DAY	$62,981	$68,115	$60,283	$45,341	$100,422	$61,853	$49,281	$74,584	$168,028	$81,438	$102,212	$122,259	20%
DOM	$89,684	$76,237	$71,013	$46,788	$76,716	$51,745	$40,594	$65,887	$165,930	$80,837	$95,971	$162,314	69%
DPL	$89,342	$43,314	$38,818	$18,293	$35,953	$19,416	$11,694	$31,060	$82,570	$47,426	$55,157	$71,346	29%
DUKE	$55,669	$63,890	$57,594	$42,793	$106,861	$57,909	$45,372	$69,534	$160,692	$78,439	$95,063	$114,360	20%
DUQ	$62,643	$74,406	$71,816	$49,873	$77,284	$44,548	$40,878	$54,321	$133,467	$85,815	$89,687	$102,809	15%
EKPC	$81,876	$66,320	$55,747	$39,454	$76,898	$50,190	$41,067	$57,851	$143,528	$68,621	$73,632	$94,172	28%
JCPLC	$110,941	$61,681	$52,688	$42,416	$51,793	$41,341	$23,460	$31,507	$58,853	$28,351	$30,152	$51,668	71%
MEC	$103,350	$87,534	$68,353	$55,898	$64,015	$45,180	$40,376	$63,212	$156,206	$64,015	$75,788	$98,738	30%
PE	$151,728	$125,644	$81,939	$55,665	$99,692	$53,422	$45,753	$68,989	$164,023	$89,111	$105,518	$147,693	40%
PECO	$107,953	$88,284	$65,466	$48,832	$62,412	$39,572	$33,222	$45,013	$91,624	$44,852	$66,049	$78,906	19%
PEPCO	$100,641	$73,941	$70,434	$42,566	$71,155	$44,697	$32,087	$49,752	$100,034	$54,400	$69,448	$106,895	54%
PPL	$204,880	$137,227	$69,121	$52,350	$96,714	$41,840	$34,576	$61,216	$159,222	$65,329	$80,078	$104,025	30%
PSEG	$131,707	$100,778	$69,820	$53,889	$67,714	$43,435	$24,685	$35,851	$61,501	$28,384	$31,162	$50,040	61%
REC	$103,106	$65,662	$56,066	$43,741	$53,424	$43,108	$25,788	$43,568	$72,081	$34,420	$37,392	$63,992	71%
PJM	$100,026	$79,990	$64,996	$45,417	$76,017	$46,839	$36,007	$53,996	$123,806	$61,995	$74,252	$100,262	35%

16 All starts associated with combined cycle units are assumed to be warm starts.
17 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs. The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CP plant energy market net revenues were higher in all zones in the first nine months of 2025 as a result of higher dark spreads (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through September, 2014 through 2025 (Dollars per installed MW-year)[18]

	Jan-Sep												
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Change in 2025 from 2024
ACEC	$113,398	$47,038	$10,176	$3,349	$29,606	$3,777	$179	$5,784	$10,591	$4,384	$6,613	$22,024	233%
AEP	$101,669	$45,454	$30,945	$26,763	$52,538	$12,589	$4,193	$40,314	$33,649	$7,768	$34,006	$85,611	152%
APS	$100,484	$40,907	$12,174	$12,354	$39,299	$4,619	$1,988	$14,164	$17,454	$10,397	$19,586	$80,778	312%
ATSI	$112,748	$47,552	$27,158	$27,067	$54,195	$10,452	$2,774	$33,583	$42,104	$9,147	$30,753	$76,412	148%
BGE	$160,039	$77,059	$42,361	$12,521	$47,695	$7,999	$4,767	$23,102	$48,926	$23,876	$29,113	$52,130	79%
COMED	$100,679	$35,752	$21,437	$21,515	$26,276	$11,102	$1,478	$39,918	$175,681	$42,490	$50,566	$95,887	90%
DAY	$104,869	$45,060	$25,861	$25,582	$52,374	$12,280	$5,245	$45,574	$32,898	$9,303	$38,150	$86,212	126%
DOM	$144,105	$81,887	$39,456	$18,363	$57,001	$12,827	$5,546	$42,998	$105,920	$21,935	$55,000	$137,279	150%
DPL	$153,229	$67,849	$20,071	$8,560	$43,597	$9,115	$4,101	$18,483	$34,764	$20,073	$21,151	$38,322	81%
DUKE	$95,548	$41,037	$23,659	$23,198	$58,239	$10,811	$4,340	$41,361	$30,385	$8,784	$33,966	$79,742	135%
DUQ	$87,906	$36,914	$23,742	$24,388	$54,041	$9,411	$3,853	$31,965	$37,383	$8,438	$30,028	$69,199	130%
EKPC	$92,512	$34,882	$19,929	$18,799	$35,031	$7,634	$3,462	$35,529	$28,127	$7,127	$31,240	$78,203	150%
JCPLC	$117,588	$46,725	$7,563	$4,344	$30,331	$3,387	$765	$5,606	$11,494	$4,183	$5,988	$20,491	242%
MEC	$144,624	$64,202	$17,424	$14,224	$43,173	$7,414	$4,754	$30,300	$69,689	$7,355	$24,006	$71,970	200%
PE	$119,745	$57,342	$21,026	$10,659	$38,207	$7,005	$3,019	$27,466	$46,167	$7,983	$31,036	$86,237	178%
PECO	$109,397	$44,739	$8,406	$3,368	$29,236	$3,625	$254	$12,268	$20,125	$4,485	$13,589	$37,017	172%
PEPCO	$112,907	$39,127	$9,917	$2,959	$29,507	$3,734	$508	$14,243	$19,419	$9,114	$19,143	$41,209	115%
PPL	$108,732	$43,645	$6,736	$3,547	$28,721	$2,338	$359	$15,285	$25,307	$4,306	$11,648	$33,411	187%
PSEG	$163,820	$72,273	$12,359	$7,058	$35,677	$5,064	$257	$5,807	$20,921	$4,825	$5,975	$21,354	257%
REC	$158,832	$72,439	$11,758	$6,912	$34,884	$5,981	$680	$11,050	$24,190	$4,322	$6,883	$22,329	224%
PJM	$120,142	$52,094	$19,608	$13,776	$40,981	$7,558	$2,626	$24,740	$41,760	$11,015	$24,922	$61,791	148%

18 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours and output reflects the class average equivalent availability factor.[19]

New entrant nuclear plant energy market net revenues were higher in all zones in the first nine months of 2025 as a result of higher energy prices (Table 7-8).

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through September, 2014 through 2025 (Dollars per installed MW-year)[20]

	Jan-Sep												
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Change in 2025 from 2024
ACEC	$360,915	$229,102	$152,141	$165,191	$213,169	$148,853	$107,061	$180,256	$389,808	$147,539	$164,119	$246,694	50%
AEP	$286,963	$204,221	$167,316	$178,362	$218,529	$163,269	$124,405	$206,222	$433,840	$189,325	$185,926	$270,353	45%
APS	$311,630	$225,877	$172,174	$179,527	$230,145	$163,243	$124,485	$204,549	$439,825	$193,181	$193,103	$275,697	43%
ATSI	$299,869	$208,113	$169,248	$181,909	$229,744	$165,213	$124,987	$203,527	$429,077	$187,587	$187,739	$270,148	44%
BGE	$400,502	$278,999	$222,930	$196,171	$255,697	$178,806	$139,161	$229,760	$506,498	$230,332	$245,031	$332,994	36%
COMED	$258,226	$175,674	$156,006	$166,122	$172,584	$147,141	$113,554	$194,154	$382,686	$164,292	$157,248	$220,366	40%
DAY	$289,914	$204,805	$168,415	$182,281	$226,966	$169,847	$130,249	$218,439	$448,879	$198,572	$194,896	$273,930	41%
DOM	$353,605	$251,055	$185,648	$188,523	$247,128	$170,020	$126,856	$221,515	$513,644	$215,302	$223,103	$347,434	56%
DPL	$384,366	$248,859	$174,096	$174,105	$232,687	$158,433	$114,761	$202,715	$413,970	$166,809	$188,137	$268,170	43%
DUKE	$278,699	$199,944	$165,436	$179,053	$234,243	$165,438	$125,799	$212,664	$441,154	$195,379	$187,317	$265,383	42%
DUQ	$270,088	$195,317	$164,951	$178,387	$229,363	$162,886	$126,588	$200,496	$420,972	$185,093	$185,561	$260,417	40%
EKPC	$274,997	$192,691	$160,945	$173,419	$203,840	$160,268	$123,371	$204,660	$435,731	$189,988	$182,785	$263,236	44%
JCPLC	$364,815	$227,874	$146,982	$169,405	$213,944	$148,377	$107,801	$180,926	$397,338	$151,037	$163,681	$247,772	51%
MEC	$349,545	$221,331	$148,453	$173,836	$213,225	$152,073	$113,794	$198,614	$456,180	$163,150	$172,963	$262,197	52%
PE	$323,485	$220,294	$160,794	$172,815	$217,995	$157,504	$118,552	$197,242	$425,954	$180,145	$190,627	$284,033	49%
PECO	$353,646	$223,312	$145,566	$164,881	$211,302	$145,791	$105,656	$178,095	$384,359	$142,144	$162,383	$240,413	48%
PEPCO	$388,376	$262,198	$198,294	$191,299	$248,756	$173,483	$129,574	$220,188	$488,466	$219,512	$230,726	$327,584	42%
PPL	$350,494	$221,731	$145,926	$167,451	$206,624	$144,711	$106,689	$185,085	$419,729	$151,063	$161,653	$237,225	47%
PSEG	$385,152	$237,992	$150,318	$171,295	$218,177	$150,459	$108,427	$185,947	$403,646	$152,583	$165,051	$248,868	51%
REC	$379,412	$239,194	$150,110	$172,155	$218,908	$153,663	$111,146	$198,097	$418,357	$163,228	$177,203	$271,391	53%
PJM	$333,235	$223,429	$165,287	$176,309	$222,151	$158,974	$119,146	$201,158	$432,506	$179,313	$185,963	$270,715	46%

19 The annual class average *equivalent availability* factor was used in the calculation of energy market net revenues.
20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were higher in all zones in the first nine months of 2025 as a result of higher and more volatile energy prices (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through September, 2014 through 2025 (Dollars per installed MW-year)

	Jan-Sep												
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Change in 2025 from 2024
ACEC	$32,623	$12,075	$2,405	$800	$9,969	$1,849	$448	$1,213	$9,466	$311	$2,436	$12,514	414%
AEP	$14,425	$3,691	$831	$1,334	$4,113	$2,109	$641	$2,657	$4,197	$467	$1,575	$10,314	555%
APS	$17,985	$7,169	$910	$1,194	$6,619	$1,864	$1,616	$2,367	$4,454	$506	$1,945	$13,492	594%
ATSI	$14,091	$3,468	$1,973	$1,660	$6,951	$1,862	$2,056	$2,231	$4,184	$503	$2,806	$10,458	273%
BGE	$49,568	$15,595	$7,196	$2,314	$12,647	$3,220	$3,503	$5,992	$12,078	$1,114	$13,467	$25,669	91%
COMED	$11,311	$2,151	$638	$1,267	$702	$1,623	$336	$2,690	$2,818	$217	$1,234	$9,066	635%
DAY	$14,235	$3,444	$905	$1,569	$3,809	$2,201	$546	$3,901	$4,336	$482	$2,289	$9,945	335%
DOM	$42,535	$11,136	$2,193	$1,798	$14,452	$2,567	$1,115	$7,182	$11,090	$1,499	$6,779	$40,474	497%
DPL	$37,438	$16,044	$3,417	$1,966	$13,916	$6,074	$7,559	$13,240	$13,160	$5,946	$11,481	$19,672	71%
DUKE	$13,404	$2,885	$1,291	$2,991	$6,473	$2,092	$417	$3,572	$4,134	$476	$1,499	$9,216	515%
DUQ	$12,963	$2,951	$2,279	$1,403	$7,949	$1,767	$3,428	$2,454	$4,159	$499	$5,116	$10,007	96%
EKPC	$14,441	$2,730	$851	$896	$1,892	$1,964	$450	$3,366	$4,213	$459	$1,491	$9,922	566%
JCPLC	$32,717	$13,021	$870	$1,103	$11,091	$1,774	$1,248	$1,098	$9,111	$314	$2,519	$11,586	360%
MEC	$31,781	$12,875	$886	$2,585	$10,938	$1,458	$1,722	$3,983	$11,703	$431	$2,740	$12,611	360%
PE	$15,964	$6,410	$876	$1,247	$5,438	$1,213	$905	$1,579	$3,995	$396	$1,734	$11,123	542%
PECO	$32,130	$12,366	$862	$1,047	$9,804	$1,852	$513	$1,254	$9,424	$292	$3,669	$13,043	256%
PEPCO	$51,173	$11,388	$2,939	$1,757	$12,291	$2,777	$1,110	$4,210	$10,574	$935	$7,995	$25,904	224%
PPL	$32,719	$13,011	$773	$1,643	$8,764	$893	$400	$1,877	$7,641	$342	$2,376	$11,652	390%
PSEG	$32,303	$12,629	$930	$1,103	$10,277	$2,120	$292	$1,626	$9,404	$308	$1,796	$11,576	545%
REC	$29,837	$13,705	$973	$1,113	$9,530	$2,084	$595	$6,116	$9,128	$331	$1,565	$11,843	657%
PJM	$29,787	$8,937	$1,700	$1,539	$8,381	$2,168	$1,445	$3,630	$7,463	$791	$3,825	$14,504	279%

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly by zone assuming the unit generated at the average hourly capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW.[21]

Onshore wind energy market net revenues excluding RECs in the defined zones were higher in the first nine months of 2025 as a result of increases in energy prices.

Table 7-10 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): January through September, 2014 through 2025

	Jan-Sep												
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Change in 2025 from 2024
AEP	$80,488	$54,850	$45,842	$48,743	$69,611	$49,912	$30,754	$47,276	$106,828	$46,094	$49,330	$70,634	43%
APS	$83,957	$55,410	$40,843	$51,330	$69,984	$42,199	$32,374	$42,649	$96,708	$45,219	$45,229	$73,998	64%
COMED	$72,887	$46,732	$39,315	$48,121	$46,613	$44,297	$26,061	$46,357	$97,383	$37,238	$41,007	$54,937	34%
PE	$101,629	$67,821	$42,369	$50,687	$69,843	$41,131	$28,813	$40,510	$90,826	$36,527	$37,069	$62,584	69%

Wind units in the four zones were assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[22] Renewable energy credits were between 65 and 98 percent of the energy market net revenue of an onshore wind installation.

Table 7-11 RECs revenue for an onshore wind installation (Dollars per installed MW-year): January through September, 2014 through 2025

	Jan-Sep											
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
AEP	$25,776	$26,578	$21,300	$8,674	$11,155	$12,634	$15,750	$24,166	$41,144	$51,199	$58,518	$46,967
APS	$25,069	$23,026	$17,918	$8,897	$10,585	$10,561	$15,973	$22,282	$35,700	$49,133	$52,874	$48,211
COMED	$28,729	$26,799	$19,853	$9,440	$10,904	$13,199	$15,897	$27,001	$45,870	$54,131	$66,417	$53,784
PE	$28,435	$27,471	$19,943	$9,006	$10,959	$10,727	$15,246	$22,548	$34,831	$41,900	$43,861	$40,543

21 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
22 RECs prices obtained from Evolution Markets, Inc.

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly for relevant zones assuming the unit generated at a 40 percent capacity factor.

Offshore wind energy market net revenues excluding RECs were higher in the first nine months of 2025 as a result of higher energy prices.

Table 7-12 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): January through September, 2014 through 2025

	Jan-Sep												
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Change in 2025 from 2024
ACEC	$149,772	$96,219	$64,564	$69,660	$90,860	$64,497	$46,801	$76,737	$170,516	$60,970	$71,916	$105,695	47%
DOM	$157,995	$104,655	$79,002	$79,539	$105,879	$72,441	$54,828	$97,137	$231,511	$91,249	$96,009	$153,034	59%
DPL	$160,094	$105,291	$71,639	$73,520	$100,412	$69,266	$51,820	$90,525	$184,874	$71,504	$81,573	$113,884	40%

The offshore wind unit in ACEC was assumed to receive NJ wind RECs. The offshore wind unit in DOM and DPL was assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[23] Renewable energy credits were between 49 and 73 percent of the energy market net revenue of an offshore wind installation.

Table 7-13 RECs revenue for an offshore wind installation (Dollars per installed MW-year): January through September, 2014 through 2025

	Jan-Sep											
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ACEC	$41,932	$42,471	$31,478	$13,411	$16,508	$17,448	$25,383	$40,722	$61,489	$84,127	$94,821	$76,830
DOM	$41,623	$41,617	$30,661	$12,780	$15,908	$17,341	$25,226	$40,717	$61,717	$82,817	$91,249	$74,924
DPL	$41,623	$41,617	$30,661	$12,780	$15,908	$17,341	$25,226	$40,717	$61,717	$82,817	$91,249	$74,924

23 RECs prices obtained from Evolution Markets, Inc.

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone with an installed capacity greater than 3 MW.[24]

Solar energy market net revenues excluding RECs in the first nine months of 2025 were higher in all zones analyzed except DOM as a result of higher energy prices.

Table 7-14 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through September, 2014 through 2025

	Jan-Sep												
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Change in 2025 from 2024
ACEC	$60,221	$43,274	$32,609	$31,056	$35,469	$27,917	$19,596	$32,504	$81,463	$25,279	$32,178	$42,903	33%
DOM	-	-	$58,175	$57,902	$65,866	$49,013	$36,735	$68,442	$193,528	$63,208	$65,750	$115,007	75%
DPL	-	-	$37,917	$42,030	$51,312	$39,029	$27,848	$40,417	$94,522	$41,173	$50,497	$61,371	22%
JCPLC	$56,051	$36,464	$28,520	$30,176	$33,486	$25,962	$19,723	$31,508	$75,466	$23,982	$27,818	$38,551	39%
PSEG	$54,074	$42,695	$32,929	$33,321	$36,560	$29,236	$21,338	$36,438	$82,821	$25,857	$29,369	$41,732	42%

The solar installation was assumed to receive the highest of the DC, MD or NJ Solar REC, based on locational eligibility, for the purposes of calculating RECs revenue.[25] Renewable energy credits were between 86 and 521 percent of the energy market net revenue of a solar installation.

Table 7-15 RECs revenue for a solar installation (Dollars per installed MW-year): January through September, 2014 through 2025

	Jan-Sep											
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ACEC	$199,423	$268,457	$300,923	$231,837	$228,873	$259,660	$239,948	$248,976	$268,602	$245,110	$232,672	$219,741
DOM	-	-	$82,731	$17,693	$15,263	$81,955	$123,533	$124,169	$106,730	$94,635	$97,965	$98,752
DPL	-	-	$58,756	$14,577	$12,859	$71,298	$99,810	$96,808	$74,279	$87,131	$81,555	$74,317
JCPLC	$190,545	$226,563	$269,055	$218,221	$214,606	$240,800	$233,348	$241,616	$247,071	$225,498	$208,303	$200,829
PSEG	$175,688	$249,664	$307,630	$239,981	$228,851	$267,446	$258,317	$264,742	$268,349	$239,679	$219,703	$211,238

24 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
25 RECs prices obtained from Evolution Markets, Inc.

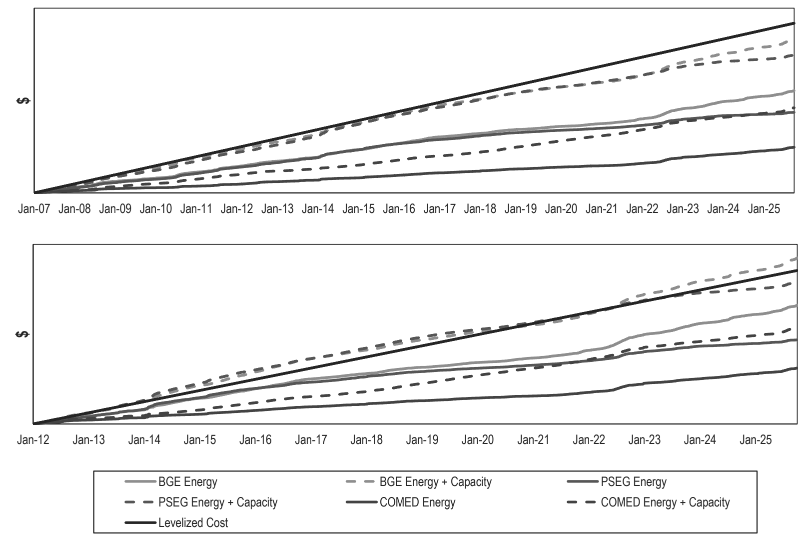
Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity market revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 91 percent of their total costs in the BGE Zone and 81 percent of total costs in the PSEG Zone, and 50 percent of total costs in the COMED Zone, including the return on and of capital, on a cumulative basis through September 2025. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered over 100 percent of their total costs on a cumulative basis in the BGE Zone, 92 percent of their total costs in PSEG Zone, and 63 percent of total costs in the COMED Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs. Covering 100 percent of total costs in this analysis includes earning the assumed rate of return. Units earned a positive rate of return even when earning less than the assumed rate of return.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation, ignoring the benefits of competition on increasing efficiency, reducing costs and improving technology and ignoring the possibility of over earning under cost of service regulation.

Figure 7-5 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CC that began operation on January 1, 2007, and a new entrant CC that began operation on January 1, 2012. The solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-5 Historical new entrant CC revenue adequacy: 2007 through September 2025 and 2012 through September 2025[26]



26 The gas pipeline pricing points used in this analysis are Zone 6 non-NY for BGE, Chicago City Gate for COMED, and Texas Eastern M3 for PSEG.

Table 7-16 shows the percent of levelized total costs recovered from the start date through September 2025. Table 7-16 also shows the return (IRR) earned from the start date through September 2025. For example, for a CC built in BGE in 2012, the resource would have earned a 14 percent IRR compared to the required 12 percent. In contrast, for a CC built in ComEd in 2012, the resource would have earned a 2 percent IRR compared to the required 12 percent.

Table 7-16 Percent of levelized total costs recovered

2007 through September 2025 and 2012 through September 2025	2007 CC	2012 CC
Percent of levelized costs covered at 12% IRR		
BGE	91%	108%
COMED	50%	63%
PSEG	81%	92%
IRR at which levelized costs are covered		
BGE	9%	14%
COMED	0%	2%
PSEG	7%	11%

The assumptions used for this analysis are shown in Table 7-17.

Table 7-17 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$20,016	$20,126
End of Life Value	$0	$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Cost of Equity (%)	12.0%	12.0%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years
IRR (%)	12.0%	12.0%

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[27] [28] The analysis includes the most recent operating cost data and incremental capital expenditure data for single unit plants and multi unit plants published by NEI, which is for 2023.[29] NEI average operating costs have decreased since their peak in 2012 (a 7.5 percent decrease from 2012 through 2023 for all plants including single and multiple unit plants in nominal dollars; a 33.0 percent decrease in real 2023 dollars).[30] NEI average incremental capital expenditures have decreased since their peak in 2012 (a 32.8 percent decrease from 2012 through 2023 for all plants including single and multiple unit plants in nominal dollars; a 51.1 percent decrease in real 2023 dollars).[31] NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[32] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were then at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs based on

27 Operating costs from: Nuclear Energy Institute (February 2025). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

28 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

29 NEI also provides average costs by plant run by operators with one plant or multiple plants, by market, and by type of nuclear reactor. Plants run by operators with multiple plants have lower average costs than plants run by operators with a single plant. Plants participating in wholesale markets have lower average costs than plants in regulated markets. PWR reactors have lower average generating costs than BWR reactors.

30 Operating costs in this paragraph are operating costs as specified by NEI and do not include fuel costs or capital expenditures. Operating costs for single unit plants decreased by 2.6 percent from 2022 to 2023 in nominal dollars. Operating costs for multiple unit plants increased by 6.0 percent from 2022 to 2023 in nominal dollars.

31 Capital expenditures have decreased 20.6 percent since 2012 for single unit plants and 35.0 percent for multiple unit plants in nominal dollars.

32 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating at a capacity factor of 100 percent. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.05 per MWh for a nuclear power plant operating at a capacity factor of 0.951 percent.

current year prices.[33] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Although energy prices in 2019 were lower than in 2016, higher capacity market revenues more than offset the difference. In 2020, PJM energy prices were at the lowest level since the introduction of competitive markets, even lower than in 2016. Average energy prices in 2022 were higher than energy prices in any year since the inception of PJM markets in 1999. Based on forward prices as of September 30, 2025, expected nuclear plant energy revenues for 2025 and 2026 are higher than actual revenues in all years since 2014, with the exception of 2022. The actual net revenue results for individual nuclear plants are a function of the degree to which actual unit costs are less than or greater than the benchmark NEI data.

Table 7-18 shows energy market prices, Table 7-19 and Table 7-20 show capacity market prices and Table 7-21 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.[34] [35] The analysis excludes the Catawba 1 nuclear unit. Partial data is provided for the Cook, North Anna, and Surry nuclear units. The AEP Cook nuclear units are designated FRR. North Anna 1 and 2 and Surry 1 and 2 are part of the Dominion FRR for the 2022/2023 and 2023/2024 and 2024/2025 Delivery Years.[36] [37] [38] FRR units receive cost of service revenues and are not subject to PJM market revenues. Duke's Catawba 1 is not in PJM but is pseudo tied to PJM.

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Historical nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd or ELCC rate.[39]

33 The MMU submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program*. Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring*.
34 Installed capacity is from NEI fact sheets accessed April 23, 2025 <https://www.nei.org/resources/fact-sheets/u-s-nuclear-plants>.
35 Constellation plans to restore TMI Unit 1 to service. Exelon. "Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid," (September 20, 2024) <https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html>.
36 See "Resources Designated in 2022/2023 FRR Capacity Plans as of April 23, 2021," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-resources-designated-in-frr-plans.ashx>
37 See "Resources Designated in 2023/2024 FRR Capacity Plans as of May 19, 2021," <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-resources-designated-in-frr-plans.pdf>
38 See "Resources Designated in 2024/2025 FRR Capacity Plans as of November 8, 2022," <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-resources-designated-in-frr-plans.pdf>
39 ELCC rates used starting with the 2025/2026 Delivery Year. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

Table 7-18 Nuclear unit day-ahead LMP: 2008 through 2024

	ICAP	Average DA LMP ($/MWh)																
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35	$26.22	$20.33	$37.07	$67.02	$29.63	$30.28
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11	$22.88	$18.23	$33.74	$58.20	$25.78	$23.31
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96	$22.19	$17.66	$32.81	$57.70	$25.36	$23.74
Calvert Cliffs	1,726	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79	$28.00	$21.88	$41.24	$78.11	$35.45	$37.05
Cook	2,177	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03	$31.44	$25.07	$19.59	$34.81	$63.46	$28.88	$28.28
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54	$37.34	$68.07	$29.63	$30.46
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25	$23.41	$18.73	$34.32	$59.35	$25.11	$24.36
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93	$22.45	$17.32	$30.16	$60.64	$22.97	$26.42
LaSalle	2,265	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19	$22.75	$18.14	$33.54	$57.90	$25.55	$23.05
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08	$22.68	$17.31	$31.05	$61.25	$23.16	$26.06
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44	$27.39	$21.06	$39.99	$76.51	$33.75	$35.11
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63	$21.58	$16.93	$30.77	$61.29	$23.01	$26.08
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76	$20.49	$37.76	$68.56	$30.39	$31.23
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54	$21.13	$15.95	$31.39	$57.82	$25.01	$23.42
Salem	2,285	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90	$22.43	$17.32	$30.12	$60.59	$22.95	$26.40
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50	$26.65	$20.41	$39.30	$74.21	$32.74	$33.65
Susquehanna	2,494	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42	$21.08	$16.03	$30.36	$59.60	$23.77	$24.13
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76	NA	NA	NA	NA	NA	NA

Table 7-19 BRA capacity market clearing prices ($/MW-Day): 2007/2008 through 2026/2027[40 41]

	ICAP	BRA Capacity Price ($/MW-Day)																			
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	$50	$34	$29	$270	$329
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329
Calvert Cliffs	1,726	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49	$270	$329
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29	$270	$329
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329
LaSalle	2,265	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA	$444	$329
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-	-	-	-	-	-
Peach Bottom	2,550	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29	$270	$329
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329
Salem	2,285	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA	$444	$329
Susquehanna	2,494	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49	$270	$329
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	-	-	-	-	-

40 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>. For the 2022/2023 Delivery Year, Surry is part of Dominion FRR.

41 Cook is designated FRR. North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year. North Anna and Surry are in the PJM Capacity Market beginning with the 2025/2026 Delivery Year.

Table 7-20 Nuclear unit capacity market revenue ($/MWh): 2008 through 2025[42 43]

	ICAP	Capacity Revenue ($/MWh)																	
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	$3.80	$1.76	$1.35	$7.40
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40
Calvert Cliffs	1,726	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.62	$4.07	$5.10	$4.97	$2.97	$2.15	$7.77
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.76	$1.35	$7.40
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84
LaSalle	2,265	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	NA	NA	NA	$11.32
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	-	-	-	-	-	-	-	-
Peach Bottom	2,550	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.76	$1.35	$7.40
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40
Salem	2,285	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	NA	NA	NA	$11.32
Susquehanna	2,494	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.06	$5.10	$4.97	$2.97	$2.15	$7.77
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	-	-	-	-	-	-	-

42 Capacity revenue through the 2024/2025 Delivery Year is calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the annual class average capacity factor. Class average EFORd and capacity factor is from *2024 Annual State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market. Capacity revenue beginning the 2025/2026 Delivery Year is calculated by adjusting the BRA Capacity Price for calendar year, by the class average ELCC. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

43 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>. Constellation is planning to restart Three Mile Island Unit 1. Constellation. "Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid," (September 20, 2024) <https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html>.

Table 7-21 Nuclear unit costs: 2008 through 2023[44] [45]

	ICAP	NEI Costs ($/MWh)															
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Calvert Cliffs	1,726	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Cook	2,177	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64	$37.42	$41.08	$41.62
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
LaSalle	2,265	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	-	-	-	-	-	-
Peach Bottom	2,550	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64	$37.42	$41.08	$41.62
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Salem	2,285	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Susquehanna	2,494	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	-	-	-	-	-

Hope Creek, Quad Cities, and Salem have all received state subsidies since 2019.[46] [47] The NJ Board of Public Utilities, having received no applications as of December 1, 2023, closed the third eligibility period of the ZEC program for the period beginning June 1, 2025.[48] This was a result of the introduction of a new federal nuclear subsidy under the Inflation Reduction Act. Braidwood, Byron, Dresden, and LaSalle will receive a state subsidy if necessary to meet a target net revenue value, in dollars per MWh, from the energy and capacity markets.[49] All existing nuclear plants will receive a federal subsidy if necessary to meet a target revenue value, in dollars per MWh, from the energy market.[50]

The Inflation Reduction Act added a significant new federal subsidy for existing nuclear power plants.[51] All existing nuclear plants will receive the Zero Emission Nuclear Power Production Credit (Nuclear PTC) if revenues from energy, ancillary, capacity markets, and any state subsidies are between $25.00/MWh and $43.75/MWh, adjusted for inflation. The Nuclear PTC of $3.00/MWh is increased by a factor of five to $15.00/MWh if certain prevailing wage requirements are met. The Nuclear PTC creates a revenue floor of $40.00/MWh and does not create a revenue ceiling. If nuclear revenues are greater than $43.75/MWh, the Nuclear PTC subsidy does not apply and units keep all profits.

44 Operating costs from: Nuclear Energy Institute (February 2025). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>.
45 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.
46 Illinois Commerce Commission, Report to the General Assembly in Compliance with Section 1-75(d-5) of the [CEJA, Public Act 102-0662,] 20 ILCS 3855/1-75(d-5)(F)(2) (August 2019). The report finds that while total ZECs payments are limited by rate impact caps and volume caps, the law's limitation does not unduly constrain the procurement of ZECs.
47 *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Hope Creek*, Order Determining the Eligibility of Hope Creek Nuclear Generator to Receive ZECs, BPU Docket No. ER20080559 (April 27, 2021). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 1, Order Determining the Eligibility of Salem Unit 1 Nuclear Generator to Receive ZECs*, BPU Docket No. ER20080557 (April 27, 201). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 2, Order Determining the Eligibility of Salem Unit 2 Nuclear Generator to Receive ZECs*. BPU Docket No. ER20080557 (April 27, 2021).
48 See *New Jersey BPU, In the Matter of the Third Eligibility Period for the Zero Emission Certificate Program Pursuant to N.J.S.A. 48:3-87.3 TO 87.7*, Order Closing the Third Eligibility Period of the Zero Emission Certificate Program, Docket No. EO23080548 (February 14, 2024).
49 CEJA, Public Act 102-0662, 20 ILCS 3855/1-75.
50 See Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).
51 See Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

Table 7-22 shows the subsidy received by nuclear units in PJM in $/MWh since 2019.

Table 7-22 Nuclear unit subsidies in $/MWh: 2019 through September 2025

	Subsidy ($/MWh)						
	2019	2020	2021	2022	2023	2024	2025
Beaver Valley	-	-	-	-	-	$9.69	$0.00
Braidwood	-	-	-	-	-	$15.00	$2.42
Byron	-	-	-	-	-	$14.93	$3.08
Calvert Cliffs	-	-	-	-	-	$3.64	$0.00
Cook	-	-	-	-	-	-	-
Davis Besse	-	-	-	-	-	$9.55	$0.00
Dresden	-	-	-	-	-	$14.43	$2.74
Hope Creek	$7.04	$10.00	$10.00	$10.00	$10.00	$12.06	$5.56
LaSalle	-	-	-	-	-	$15.00	$2.38
Limerick	-	-	-	-	-	$12.35	$0.00
North Anna	-	-	-	-	-	$6.91	$0.00
Oyster Creek	-	-	-	-	-	-	-
Peach Bottom	-	-	-	-	-	$12.33	$0.00
Perry	-	-	-	-	-	$8.94	$0.00
Quad Cities	$16.50	$16.50	$16.50	$16.50	$16.50	$16.50	$16.50
Salem	$7.04	$10.00	$10.00	$10.00	$10.00	$12.08	$5.56
Surry	-	-	-	-	-	$8.08	$0.00
Susquehanna	-	-	-	-	-	$13.98	$0.00
Three Mile Island	-	-	-	-	-	-	-

Table 7-23 shows the surplus or shortfall in $/MWh for the 16 nuclear plants in PJM, and Oyster Creek and Three Mile Island, calculated using historic LMP and cost data. In 2020, no nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy prices. In 2021 and 2022, all nuclear plants more than covered their fuel costs, operating costs, and capital expenditures as a result of higher energy prices. In 2023, only two nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy and capacity prices. In 2024, all nuclear plants with the exception of Davis Besse covered their fuel costs, operating costs, and incremental capital expenditures. The surplus or shortfall assumes that the unit receives the DA LMP, reactive capability revenue, cleared its full unforced capacity at the BRA locational clearing price, receives a subsidy if qualified, and has costs equal to the NEI average costs.[52] Unforced capacity is determined using the annual class average EFORd or ELCC rate.[53]

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market in some years as a result of decisions by plant owners about how to offer the plants in the capacity market auctions. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not accurately reflect the economic viability of the plants. This analysis is intended to define whether the plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices, then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Quad Cities and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[54] Quad Cities did not clear in the 2020/2021 Auction.[55] Dresden and most of Byron did not clear in the 2021/2022 Auction.[56] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[57] Byron, Dresden, and Quad Cities did not clear in the 2022/2023 Auction.[58]

Nuclear unit revenue is a combination of energy market revenue, ancillary services market revenue and capacity market revenue. Negative energy market prices do not have a significant impact on nuclear unit revenue. Since 2014, negative energy market prices have affected nuclear plants' annual total revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant total revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an

52 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.
53 ELCC rates used starting with the 2025/2026 Delivery Year. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.
54 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
55 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
56 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.
57 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>.
58 NuclearNewswire. "Byron, Dresden, Quad Cities Fail to Clear in PJM Capacity Auction," (June 8, 2021) <https://www.ans.org/news/article-2967/byron-dresden-quad-cities-fail-to-clear-in-pjm-capacity-auction/>.

average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, an average of 0.0 percent and a maximum of 0.0 percent in 2018, an average of 0.0 percent and a maximum of 0.2 percent in 2019, an average of 0.1 percent and a maximum of 1.7 percent in 2020, an average of 0.0 percent and a maximum of 0.3 percent in 2021, an average of 0.0 percent and a maximum of 0.0 percent in 2022, an average of 0.0 percent and a maximum of 0.1 percent in 2023, an average of 0.6 percent and a maximum of 4.9 percent in 2024 and an average of 0.1 percent and a maximum of 0.5 percent in the first nine months of 2025.[59]

Table 7-23 shows the surplus or shortfall for the 16 nuclear plants in PJM in $/MWh, including subsidies.

Table 7-23 Nuclear unit surplus (shortfall) based on public data in $/MWh: 2008 through 2024

	ICAP	Surplus (Shortfall) ($/MWh)																
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.4)	$2.6	$13.9	$3.7	($2.7)	$15.0	$42.4	$2.1	$12.0
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.2)	($1.6)	$5.9	$3.9	($0.0)	$15.1	$35.0	($1.5)	$10.3
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.6)	($2.8)	$5.8	$3.2	($0.6)	$14.1	$34.5	($1.9)	$10.6
Calvert Cliffs	1,726	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$5.4	($0.9)	$19.4	$54.6	$9.1	$13.5
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.3)	($15.1)	$5.9	$31.6	($10.0)	($0.0)
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.6)	($0.1)	$7.1	$4.5	$0.5	$15.7	$36.2	($2.1)	$10.8
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($1.9)	$1.6	$12.3	$8.8	$7.8	$21.0	$48.0	$6.9	$11.7
LaSalle	2,265	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.6)	($1.9)	$6.0	$3.7	($0.2)	$14.8	$34.7	($1.8)	$10.0
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.1)	$1.5	$12.1	$1.6	($2.6)	$11.6	$38.2	($3.3)	$11.2
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.8	($2.0)	$17.9	NA	NA	NA
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.9	$0.6	($2.8)	$11.4	$38.3	($3.3)	$11.3
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.4)	$1.9	($5.9)	($15.2)	$6.2	$32.0	($9.3)	$0.0
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.3	$18.8	$14.4	$29.4	$51.3	$14.4	$12.1
Salem	2,285	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.1)	$1.5	$12.2	$8.5	$7.5	$20.7	$47.6	$6.6	$11.4
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.6	$4.5	$16.0	$4.2	($2.5)	$17.4	NA	NA	NA
Susquehanna	2,494	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.1	($1.7)	($6.9)	$8.3	$35.9	($2.8)	$10.7
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA	NA	NA	NA	NA

59 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.

Table 7-24 shows the surplus or shortfall for the 16 nuclear plants in PJM in dollars, including subsidies.

Table 7-24 Nuclear unit surplus (shortfall) based on public data ($M): 2008 through 2024

	ICAP	Surplus (Shortfall) ($ in millions)																
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Beaver Valley	1,808	$393.5	$93.3	$156.3	$131.1	($49.4)	$21.0	$174.8	$47.7	($8.9)	$35.7	$204.3	$51.0	($42.5)	$223.0	$632.2	$28.2	$178.2
Braidwood	2,337	$482.3	$48.3	$122.8	$65.2	($118.7)	($49.6)	$138.9	($22.7)	($65.2)	($33.3)	$110.8	$70.7	($4.2)	$290.0	$674.9	($32.4)	$197.7
Byron	2,300	$465.5	($24.2)	$64.1	($10.5)	($178.9)	($68.6)	$93.2	($116.7)	($185.2)	($55.5)	$106.4	$56.6	($14.8)	$267.5	$654.7	($40.0)	$201.5
Calvert Cliffs	1,726	$865.9	$297.3	$406.9	$254.8	$64.5	$208.4	$449.6	$201.4	$100.7	$84.7	$229.8	$74.0	($15.3)	$275.3	$778.7	$128.6	$191.9
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($98.0)	($51.4)	$48.6	($8.6)	($31.5)	($63.7)	($8.4)	($47.2)	($111.5)	$42.1	$232.3	($76.7)	($1.9)
Dresden	1,797	$380.7	$44.6	$112.9	$65.7	($77.7)	($15.0)	$134.6	$4.4	($26.5)	($5.5)	$102.2	$62.2	$4.1	$231.7	$536.2	($34.9)	$159.3
Hope Creek	1,172	$523.2	$164.8	$237.0	$163.2	$24.8	$119.9	$251.6	$60.5	($23.2)	$11.2	$114.5	$79.9	$70.3	$200.6	$461.3	$63.3	$109.7
LaSalle	2,265	$464.9	$45.9	$119.9	$61.5	($114.1)	($35.3)	$144.7	($16.3)	($69.8)	($37.5)	$109.0	$66.1	($5.6)	$277.3	$648.5	($35.8)	$186.8
Limerick	2,242	$1,003.7	$316.3	$457.2	$307.6	$47.8	$226.5	$476.3	$120.1	($41.1)	$25.3	$221.7	$28.2	($48.7)	$213.8	$707.9	($63.4)	$208.5
North Anna	1,892	$813.9	$228.5	$397.7	$262.7	$3.5	$89.3	$362.6	$170.2	$44.3	$71.2	$246.5	$71.4	($33.3)	$279.3	NA	NA	NA
Oyster Creek	608	$239.0	$42.4	$79.7	$35.9	($41.1)	$16.4	$82.3	($23.4)	($58.2)	($49.6)	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$1,133.0	$356.3	$508.8	$338.5	$48.4	$259.6	$537.6	$122.6	($53.0)	$23.7	$242.9	$9.1	($63.3)	$237.2	$805.9	($75.2)	$237.3
Perry	1,240	NA	NA	NA	NA	($135.8)	($65.3)	$56.6	($3.5)	($43.2)	($77.5)	$16.9	($61.1)	($155.2)	$62.6	$327.2	($98.4)	($1.1)
Quad Cities	1,819	$363.1	($6.7)	$36.3	($27.7)	($199.0)	($103.5)	$8.6	($115.3)	($145.0)	($54.5)	$62.7	$274.3	$207.9	$439.8	$768.4	$214.6	$178.4
Salem	2,285	$1,021.3	$322.8	$461.9	$317.9	$48.2	$233.1	$490.0	$117.1	($45.5)	$21.3	$222.5	$155.5	$136.9	$390.3	$898.3	$123.0	$213.8
Surry	1,676	$676.9	$190.3	$334.4	$226.4	($0.4)	$71.2	$298.9	$148.8	$33.5	$60.4	$219.1	$53.2	($38.4)	$237.8	NA	NA	NA
Susquehanna	2,494	$965.9	$312.8	$461.6	$332.2	$29.4	$229.0	$506.6	$129.9	($39.7)	$31.2	$201.0	($34.4)	($141.3)	$172.0	$742.6	($58.4)	$223.5
Three Mile Island	803	$270.5	$42.9	$88.2	$30.2	($63.7)	$5.9	$90.7	($45.2)	($82.3)	($68.1)	($25.3)	NA	NA	NA	NA	NA	NA

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2025, 2026, and 2027 and known capacity market prices for 2024 and 2025. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known through the 2025/2026 Delivery Year, actual energy prices will vary from forward values. Nuclear plants may choose to sell their output at a range of forward prices and for a range of future years.

Table 7-25 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2025 through 2027. Capacity revenues for calendar year 2026 include five months of capacity revenue from the 2025/2026 Delivery Year and seven months of capacity revenue for the 2026/2027 Delivery Year. Capacity revenues for calendar year 2027 include five months of capacity revenue from the 2026/2027 Delivery Year and seven months of capacity revenue assuming a clearing price of $325/MW-Day for the 2027/2028 Delivery Year.[60] The 2027/2028 BRA has not yet been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[61] Forward prices are as of September 30, 2025. The capacity prices are known through May 31, 2027, based on PJM capacity auction results.

60 On February 20, 2025, PJM filed with FERC to establish a maximum price of approximately $325/MW-day in unforced capacity and a minimum price of approximately $175/MW-day, both in unforced capacity (UCAP) terms for all capacity auctions for the 2026/2027 and 2027/2028 delivery years. See Docket No. ER25-1357.

61 Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2024 data.

Table 7-25 Forward prices in PJM energy markets, capacity revenue, and annual costs

	ICAP (MW)	Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)			2023 NEI Costs ($/MWh)		
		2025	2026	2027	Reactive	2025	2026	2027	Fuel	Operating	Capital
Beaver Valley	1,808	$43.29	$50.41	$51.63	$0.21	$7.40	$13.24	$14.20	$5.27	$18.03	$6.23
Braidwood	2,337	$33.33	$38.00	$38.96	$0.17	$7.40	$13.24	$14.20	$5.27	$18.03	$6.23
Byron	2,300	$32.50	$38.69	$39.77	$0.15	$7.40	$13.24	$14.20	$5.27	$18.03	$6.23
Calvert Cliffs	1,726	$51.53	$56.43	$57.73	$0.19	$7.77	$13.24	$14.20	$5.27	$18.03	$6.23
Cook	2,177	$41.73	$47.34	$48.50	$0.13	NA	NA	NA	$5.27	$18.03	$6.23
Davis Besse	894	$44.48	$48.09	$49.41	$0.21	$7.40	$13.24	$14.20	$5.50	$25.40	$10.72
Dresden	1,797	$32.92	$40.29	$41.43	$0.23	$7.40	$13.24	$14.20	$5.27	$18.03	$6.23
Hope Creek	1,172	$40.51	$45.65	$46.79	$0.47	$7.84	$13.24	$14.20	$5.27	$18.03	$6.23
LaSalle	2,265	$33.37	$37.93	$38.88	$0.13	$7.40	$13.24	$14.20	$5.27	$18.03	$6.23
Limerick	2,242	$40.25	$45.06	$46.20	$0.10	$7.84	$13.24	$14.20	$5.27	$18.03	$6.23
North Anna	1,892	$49.81	$54.91	$56.22	$0.18	$11.32	$8.39	$8.28	$5.27	$18.03	$6.23
Peach Bottom	2,550	$40.44	$45.08	$46.24	$0.31	$7.84	$13.24	$14.20	$5.27	$18.03	$6.23
Perry	1,240	$45.22	$51.67	$52.92	$0.21	$7.40	$13.24	$14.20	$5.50	$25.40	$10.72
Quad Cities	1,819	$30.68	$36.60	$37.71	$0.13	$7.40	$13.24	$14.20	$5.27	$18.03	$6.23
Salem	2,285	$40.49	$45.62	$46.77	$0.35	$7.84	$13.24	$14.20	$5.27	$18.03	$6.23
Surry	1,676	$47.08	$52.89	$54.16	$0.16	$11.32	$8.39	$8.28	$5.27	$18.03	$6.23
Susquehanna	2,494	$36.40	$42.22	$43.25	$0.32	$7.77	$13.24	$14.20	$5.27	$18.03	$6.23

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant.

Based on the FERC order allowing the inclusion of major maintenance in energy offers, major maintenance costs can no longer be included in gross ACR values offered in the capacity market.[62] The MMU calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant with major maintenance included in avoidable costs and with major maintenance excluded from avoidable costs. For the case including major maintenance, gross ACR is NEI total cost including fuel, operating cost, and incremental capital expenditures. For the case excluding major maintenance, gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM, given that NEI does not provide a breakout of major maintenance. NEI incremental capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

62 See 167 FERC ¶ 61,030 at P 41 (2019).

All generating plants including nuclear plants must cover their gross avoidable costs, including major maintenance, to remain economically viable. All of the MMU analysis of nuclear plant economics includes gross avoidable costs as reported by NEI unless explicitly stated otherwise.

In Table 7-26, the capacity price required to cover avoidable costs in $/MWh is calculated by taking the total NEI costs in $/MWh and subtracting the total expected energy and ancillary services revenues in $/MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average capacity factor. Total expected ancillary services revenue is unit specific reactive capability revenue.[63] The capacity price required to cover avoidable costs in $/MW-day is calculated by multiplying the required price in $/MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-26, the capacity price required to cover avoidable costs is $0/MW-day for all units in 2025, 2026 and 2027 using NEI data as reported including capital expenditures, and is $0/MW-day for all plants, excluding capital expenditures as a proxy for major maintenance, in 2025, 2026, and 2027.[64] Net revenues based on forward energy prices alone are greater than or equal to avoidable costs in 2025, 2026, and 2027 without any contribution from capacity market revenues for all plants. The result is that net ACR values for 2025, 2026 and 2027 in Table 7-26 are zero.

63 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.
64 PJM's tariff definition of avoidable costs excludes major maintenance. PJM includes major maintenance costs in the definition of short run marginal costs in energy offers.

Table 7-26 Net ACR

	ICAP	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2025	2026	2027	2025	2026	2027	2025	2026	2027
Beaver Valley	1,808	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Braidwood	2,337	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Byron	2,300	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Calvert Cliffs	1,726	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cook	2,177	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dresden	1,797	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hope Creek	1,172	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
LaSalle	2,265	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Limerick	2,242	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
North Anna	1,892	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Peach Bottom	2,550	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Perry	1,240	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Quad Cities	1,819	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Salem	2,285	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Surry	1,676	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Susquehanna	2,494	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table 7-27 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2023 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-27 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

The 2025 nuclear unit surplus values are shown in Table 7-27 based on forward prices as of September 30, 2025, NEI average costs, and expected subsidy values.[65] The current analysis, based on forward prices for energy, known forward prices for capacity, and an assumed clearing price of $325/MW-Day for the 27/28 delivery year, shows that all PJM nuclear plants analyzed are expected to have a surplus without any subsidy amount in 2025, 2026 and 2027.[66]

65 Gross receipts used to calculate the unit subsidy include energy revenue, ancillary services revenue, capacity revenue, and state ZECs subsidies, and assumes the unit meets prevailing wage requirements and receives the Zero Emission Nuclear Power Production Credit 5 times multiplier. Effectively, nuclear power plants will receive the higher of the state or federal subsidy amount.
66 On February 20, 2025, PJM filed with FERC to establish a maximum price of approximately $325/MW-day in unforced capacity and a minimum price of approximately $175/MW-day, both in unforced capacity (UCAP) terms for all capacity auctions for the 2026/2027 and 2027/2028 Delivery Years. See Docket No. ER25-1357.

Table 7-27 Nuclear unit forward annual surplus (shortfall) for 2025, 2026 and 2027[67 68 69]

	Surplus (Shortfall) ($/MWh)			Subsidy ($/MWh)			Surplus (Shortfall) Excluding Subsidy ($ in millions)			Surplus (Shortfall) Including Subsidy ($ in millions)		
	2025	2026	2027	2025	2026	2027	2025	2026	2027	2025	2026	2027
Beaver Valley	$21.37	$34.22	$36.30	$0.00	$7.45	$0.00	$321.9	$515.35	$546.76	$321.9	$627.6	$546.8
Braidwood	$11.37	$21.79	$23.63	$2.30	$11.60	$0.00	$221.4	$424.27	$460.06	$266.2	$650.1	$460.1
Byron	$10.52	$22.47	$24.44	$2.95	$11.40	$0.00	$201.6	$430.49	$468.32	$258.2	$648.9	$468.3
Calvert Cliffs	$29.96	$40.22	$42.40	$0.00	$5.45	$0.00	$430.8	$578.32	$609.73	$430.8	$656.7	$609.7
Cook	NA	NA	NA	$1.50	$0.00	$0.00	NA	NA	NA	NA	NA	NA
Davis Besse	$10.47	$19.80	$21.99	$0.00	$8.20	$0.00	$78.0	$147.46	$163.81	$78.0	$208.5	$163.8
Dresden	$11.02	$24.10	$26.10	$2.55	$10.80	$0.00	$165.0	$360.84	$390.77	$203.2	$522.5	$390.8
Hope Creek	$19.29	$29.56	$31.46	$4.17	$0.80	$0.00	$188.4	$288.58	$307.20	$229.0	$296.4	$307.2
LaSalle	$11.37	$21.70	$23.55	$2.30	$11.65	$0.00	$214.6	$409.45	$444.45	$258.0	$629.3	$444.5
Limerick	$18.66	$28.82	$30.87	$0.00	$9.30	$0.00	$348.5	$538.24	$576.63	$348.5	$711.9	$576.6
North Anna	NA	$33.85	$34.98	$0.00	$9.85	$0.00	NA	$659.45	$644.62	NA	$814.7	$644.6
Peach Bottom	$19.07	$28.92	$30.92	$0.00	$9.15	$0.00	$405.0	$614.46	$656.82	$405.0	$808.8	$656.8
Perry	$11.21	$23.38	$25.50	$0.00	$7.00	$0.00	$115.8	$241.49	$263.45	$115.8	$313.8	$263.5
Quad Cities	$8.68	$20.37	$22.38	$16.50	$16.50	$0.00	$131.5	$308.68	$339.14	$381.5	$558.7	$339.1
Salem	$19.15	$29.48	$31.44	$4.17	$0.90	$0.00	$364.5	$561.25	$598.49	$443.8	$578.4	$598.5
Surry	NA	$31.82	$32.91	$0.00	$10.55	$0.00	NA	$555.80	$542.21	NA	$703.1	$542.2
Susquehanna	$14.96	$26.07	$27.93	$0.00	$10.05	$0.00	$310.9	$541.62	$580.25	$310.9	$750.4	$580.3

67 The state subsidy value for Braidwood, Byron, Dresden, and LaSalle is calculated by taking the applicable Baseline Cost less forward energy prices and known capacity prices.
68 The federal subsidy value for nuclear plants is defined in the Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).
69 North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year. North Anna and Surry rejoined the PJM Capacity Market beginning with the 2025/2026 Delivery Year.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. State and federal environmental regulatory requirements affect the economic viability of resources and will result in the retirement of a significant level of capacity resources by 2030. State and federal environmental policies also affect the viability of new resources and the cost of entry. State and federal subsidies for renewable generation have made new solar resources cost competitive with existing coal resources and contributed to the significant level of wind and solar resources entering the market.

Overview

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[1] On April 24, 2024, the EPA finalized a strengthened and updated MATS rule reflecting recent developments in control technologies and the performance of coal fired plants.[2] On June 11, 2025, the EPA proposed to repeal the core changes of the 2024 amendments,[3] including the revised filterable particulate matter (fPM) emission standard, restoring the 0.030 lbs/MMBtu standard.[4]
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[5] (Transport Rule) On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[6] On February 28, 2022, the EPA issued a federal implementation plan for implementation of CSAPR (also known as the Good Neighbor Plan),[7] which applies when no state implementation plan has been approved. On June 27, 2024, the Supreme Court of the United States granted a stay of the federal implementation plan pending judicial review.[8] The effect of the stay is to eliminate the ozone season NO_X emissions budgets for electric generating units in the PJM states. Unless and until the stay is lifted, no federal implementation plan is effective in PJM states and the state emissions budgets are not effective. The EPA had previously rejected all proposed state implementation plans for PJM states. Under the new administration the future of the federal implementation plan is uncertain, and attempts to create state implementation plans are expected to resume.
- **NSR.** The CAA's NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.[9] NSR requires permits before construction commences. NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units.[10]
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested

1 See *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).
2 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, Final Rule, Docket No. EPA-HQ-OAR-2018-0794, 89 Fed. Reg. 38508 (May 7, 2024).
3 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, Final Rule, Docket No. EPA-HQ-OAR-2018-0794, 89 Fed. Reg. 38508 (May 7, 2024).
4 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA–HQ–OAR–2018–0794; FRL–6716.4–01–OAR, 90 Fed. Reg. 25535 (June 17, 2025).
5 CAA § 110(a)(2)(D)(i)(I).
6 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA–HQ–OAR–2020–0272; FRL–10013–42– OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
7 See *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Docket No. EPA–HQ–OAR–2021–0668; FRL 8670–01–OAR, 87 Fed. Reg. 20036 (April 6, 2022).
8 Ohio v. EPA, Slip Op. No. 23A349. (S. Ct. June 27, 2024); Utah v. EPA, D.C. Cir. Case No. Case No. 23-1157, et al.
9 42 U.S.C § 7470 et seq.
10 40 CFR § 52.21.

annually.[11] Environmental regulations allow stationary emergency RICE that do not meet the emissions limits and are participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

PJM does not prevent stationary emergency RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some stationary emergency RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Stationary emergency RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

- **Greenhouse Gas Emissions.** On April 25, 2024, the EPA issued a rule (called "Carbon Emissions Rule" in this report) taking four separate actions under CAA § 111(a)(1) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs):[12] the rule repeals the Affordable Clean Energy (ACE) Rule; the rule finalizes emission guidelines for GHG emissions from existing coal fired and oil/gas fired steam generating EGUs; the rule revises the New Source Performance Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs; the rule revises the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The rule deferred action on emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines.

  The Carbon Emissions Rule reflects the application of the best system of emission reduction (BSER). The proposal includes emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs (including coal, oil or gas). For coal fired EGUs, compliance is required by January 1, 2030, with standards that vary based on whether the EGU commits to retire before 2032, 2035, 2040, or does not commit to retire before 2040.[13] The Carbon Emissions Rule proposes to repeal the Affordable Clean Energy Rule.[14]

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[15]

- **Waters of the United States.** On August 29, 2023, the EPA issued a final rule defining adjacent wetlands consistent with the Supreme Court holding that an adjacent wetland is "… a relatively permanent body of water connected to traditional interstate navigable waters … and … that the wetland has a continuous surface connection with that water."[16] The rule became effective on September 8, 2023.[17]

- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. Since 2015, the EPA has been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result. In May 2024, the EPA finalized a rule strengthening regulation of effluent discharges.[18]

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[19] The EPA has adopted significant changes to the implementing regulations that will require closing noncompliant impoundments, and, as a result, the host power plant. The EPA is implementing a process for extensions to as late as October 17, 2028. The EPA is reviewing applications received

11 See 40 CFR § 63.6640(f).
12 See *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, Proposed Rule, Docket No. EPA-HQ-OAR-2023-0072, 89 Fed. Reg. 39798 (May 9, 2024) ("Carbon Emissions Rule").
13 Carbon Emissions Rule at 33371-33373.
14 Carbon Emissions Rule at 33243.
15 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (August 15, 2014).
16 See Revised Definition of "Waters of the United States," EPA-HQ-OW-2023-0346, 88 Fed. Reg. 61964 (September 8, 2023).
17 See *id.*
18 See *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Final Rule, EPA Docket No. EPA-HQ-OW-2009-0819; FRL-8794-01- OW, 89 Fed. Reg. 40199 (May 9, 2024).
19 42 U.S.C. §§ 6901 *et seq.*

from PJM plant owners for extensions of the deadline for compliance with the revised Coal Combustion Residuals Rule.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont that applies to power generation facilities. The most recent RGGI auction, held on September 3, 2025, cleared at $22.25 per short ton, or $24.53 per metric tonne.
- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandated that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis. More than 10,000 MW of capacity are currently affected. The CEJA operating hour limits have resulted in significant opportunity cost adders to cost-based energy market offers for affected units.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would have increased by $24.45 per MWh or 62.1 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 57.7 percent for a new combined cycle (CC) unit and $43.12 per MWh or 111.4 percent for a new coal plant (CP) for the first nine months of 2025.
- **Offshore Wind.** New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[20] On January 20, 2025, the Trump Administration issued a Presidential Memorandum withdrawing "from disposition for wind energy leasing all areas within the Offshore Continental Shelf."[21] The withdrawal effectively puts on hold indefinitely the offshore wind projects in New Jersey and Maryland. On May 5, 2025, the Attorneys General of New Jersey and Maryland, along with the 16 other states, filed suit against the withdrawal of offshore leasing.[22]

20 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.
21 *Temporary Withdrawal of all Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects*, Presidential Memorandum (January 20, 2025) <https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/>.

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of September 30, 2025, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Indiana has a voluntary renewable portfolio standard. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $14.6 billion over the ten year period from 2014 through 2023, an average annual RPS compliance cost of $1.5 billion. The compliance cost for 2023, the most recent year with almost complete data, was $2.9 billion.[23]

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of September 30, 2025, 98.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, 99.8 percent of coal steam MW had some type of particulate matter (PM) control, and 99.7 percent of coal steam MW had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

22 State of New York v. Trump, Case No. 1:25-cv-11221 (Dist. of Mass. May 5, 2025).
23 The 2023 compliance cost value for PJM states does not include Delaware, Michigan or North Carolina. Based on past data these states generally account for approximately 2.0 percent of the total RPS compliance cost of PJM states.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 6.5 percent of total generation in PJM for the first nine months of 2025. RPS Tier I generation was 7.6 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM for the first nine months of 2025. Only Tier I generation is defined to be renewable but Tier I includes some carbon emitting generation.
- PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first nine months of 2025, Tier I generation from PJM generators met only 46.8 percent of the Tier I RPS requirements.

Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that stationary emergency RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets.

Environmental requirements and initiatives at both the federal and state levels, and state renewable energy mandates and associated subsidies have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources, and the retirement of emitting resources. Renewable energy credit (REC) markets created by state programs, federal subsidies, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, including supporting some emitting resources, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

In the absence of a PJM market carbon price, a single PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor.

RECs are an important mechanism used by PJM states to implement environmental policy. RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data.

Existing REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The economic logic of RPS programs and the associated REC and SREC prices are not always clear. The price of carbon implied by REC prices ranges from $10.24 per tonne in Ohio to $65.23 per tonne in Virginia. The price of carbon implied by SREC prices ranges from $69.05 per tonne in Pennsylvania to $832.21 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in September 2025 of $24.53 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[24] [25] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.85 per MWh.[26] The impact of an $800 per tonne carbon price would be $269.59 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

If the states chose this policy option, PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests,

24 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

25 A recent update by the EPA estimates the social cost of carbon emissions for 2030 to be between $140 and $380 per metric ton (2020 dollars). See Table ES.1 in Report on the Social Cost of Greenhouse Gases, U.S. Environmental Protection Agency (November 2023) <https://www.epa.gov/environmental-economics/scghg>.

26 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 52.91 kg per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2025 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-9.

with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. The results of the analysis would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state.

For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the ten year period from 2014 through 2023 for the ten jurisdictions that had RPS was $1.5 billion, or a total of $14.6 billion over ten years. The RPS compliance cost for 2023, the most recent year for which there is almost complete data, was $2.9 billion.[27] RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $7.4 billion per year if the carbon price were $22.25 per short ton and emissions levels were five percent below 2024 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $16.5 billion if the carbon price were $50 per short ton and emission levels were five percent below 2024 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $22.25 per short ton would be about $5.0 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

27 The 2023 compliance cost value for PJM states does not include Delaware, Michigan or North Carolina. Based on past data these states generally account for approximately 2.0 percent of the total RPS compliance cost of PJM states.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.[28]

The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[29] [30]

The CWA regulates discharges from point sources that affect water quality and temperature.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[31] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

28 For more details, see the *2024 Annual State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."
29 42 U.S.C. § 7401 et seq. (2000).
30 The EPA defines a "major source" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.
31 42 U.S.C. §§ 6901 *et seq.*

The EPA's actions have affected and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, acid gas, nickel, selenium and cyanide.

The EPA's MATS rule applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[32] On February 13, 2023, the EPA issued a final rule reaffirming that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost.[33] This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112, and would restore the basis for the MATS rule.

On April 24, 2024, the EPA finalized a strengthened and updated MATS rule reflecting recent developments in control technologies and the performance of coal fired plants.[34] The EPA allows plants to meet emissions requirements for non-HAP metals under an alternative fPM emission standard as a surrogate, and most use that approach.[35] The core proposal would revise the (non Hg) fPM emission standard, from 0.030 to 0.010 lbs/MMBtu.[36] The EPA "does not project that any EGUs will retire in response to the standards promulgated in this final rule."[37]

The new administration has taken steps to weaken the enforcement of the MATS rule. In April 2025, in an administrative decision by the EPA under Administrator Lee Zeldin, citing Section 112(i)(4) of the CAA, 47 coal-fired power plants were exempted from MATS compliance for two years. The decision was based on a determination of a need to prolong the life of aging coal plants and support national energy interests. This action is temporary and does not repeal the MATS rule. Repeal of the MATS has been identified as an EPA regulatory goal.[38]

Potentially 16,661 MW of generation in PJM is covered by the two year exemption. Most of the units have either not indicated plans to retire or have repowered, so the impact of the extension alone may not be direct and immediate.

On June 11, 2025, the EPA proposed to repeal the core changes of the 2024 amendments, including the revised filterable particulate matter (fPM) emission standard, restoring the 0.030 lbs/MMBtu standard.[39]

CAA: NAAQS/CSAPR

The CAA requires each state to attain and maintain compliance with particulate matter (PM) and ozone national ambient air quality standards (NAAQS).[40] Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

In January 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state

32 See *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).

33 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding*, Final Action, EPA–HQ–OAR–2018–0794, 88 Fed. Reg. 13959 (March 6, 2023).

34 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, Final Rule, Docket No. EPA-HQ-OAR-2018-0794, 89 Fed. Reg. 38508 (May 7, 2024).

35 *Id.* at 38510.

36 *Id.* at 38518.

37 *Id.* at 38526.

38 See EPA, EPA Launches Biggest Deregulatory Action in U.S. History (March 12, 2025) ("March 12th EPA Deregulation Notice"), which can be accessed at: <https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history>.

39 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA–HQ–OAR–2018–0794; FRL–6716.4–01–OAR, 90 Fed. Reg. 25535 (June 17, 2025).

40 The particulate matter (PM) regulated under the CAA is classified as either PM_{10}, which refers to PM less than 10 microns, and $PM_{2.5}$, which refers PM less than 2.5 microns. $PM_{2.5}$ is referred to as fine particular matter and poses the greatest risk to health. Examples of $PM_{2.5}$ include combustion particles, metals, and organic compounds.

to meet NAAQS. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle emissions and 2006 fine particle emission NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

On March 15, 2021, in response to a court holding in Wisconsin v. EPA,[41] the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[42] On February 28, 2022, the EPA proposed a Federal Implementation Plan (FIP) (at that time termed the Transport Rule) for 26 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[43] The proposed FIP requirements would establish ozone season NO_X emissions budgets for electric generating units in the PJM states, excluding North Carolina and the District of Columbia.

On March 15, 2023, the EPA finalized Federal Implementation Plan (FIP) requirements for 23 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[44] The FIP, also known as the Good Neighbor Plan, resolves the CAA good neighbor obligations of the affected states and applies when no state implementation plan has been approved. The FIP requirements establish ozone season NO_X emissions budgets for electric generating units in the following PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia. The list of PJM jurisdictions excludes North Carolina, the District of Columbia, Tennessee and Delaware. Electric generating units in the indicated states would be required to participate in a revised version of the CSAPR NO_X Ozone Season Group 3 Trading Program that was previously established in the 2021 CSAPR Update.

The EPA's emissions budgets for each PJM state for each ozone season for 2023 through 2029, and beyond are shown in Table 8-1.

Table 8-1 CSAPR NO_X ozone season group 3 state budgets: 2023 through 2029[45]

	Emissions Budget (Tons)							
PJM State	2023	2024	2025	2026	2027	2028	2029	2030+
Illinois	7,474	7,325	7,325	5,889*	5,363*	4,555*	4,050*	*
Indiana	12,440	11,413	11,413	8,410*	8,135*	7,280*	5,808*	*
Kentucky	13,601	12,999	12,472	10,190*	7,908*	7,837*	7,392*	*
Maryland	1,206	1,206	1,206	842*	842*	842*	842*	*
Michigan	10,727	10,275	10,275	6,743*	5,691*	5,691*	4,656*	*
New Jersey	773	773	773	773*	773*	773*	773*	*
Ohio	9,110	7,929	7,929	7929*	7,929*	6,911*	6,409*	*
Pennsylvania	8,138	8,138	8,138	7,512*	7,158*	7,158*	4,828*	*
Virginia	3,143	2,756	2,756	2,565*	2,373*	2,373*	1,951*	*
West Virginia	13,791	11,958	11,958	10,818*	9,678*	9,678*	9,678*	*

*The budget for these years will be subsequently determined and equal the greater of the value above or that derived from the dynamic budget methodology.

On February 7, 2024, the EPA issued a final rule reducing the primary annual $PM_{2.5}$ standard to 9.0 µg/m^3 from 12.0 µg/m^3.[46] The rule does not change other $PM_{2.5}$ standards. The proposal responds to the directive in Executive Order 13990 for review of a 2020 Particulate Matter NAAQS Decision that left $PM_{2.5}$ standards unchanged.

On June 27, 2024, the Supreme Court of the United States granted a stay of the FIP and therefore the EPA's enforcement of CSAPR pending judicial review.[47] The effect of the stay is to eliminate the ozone season NO_X emissions budgets for electric generating units in the PJM states. Unless and until the stay is lifted, no federal implementation plan is effective in PJM states and the emissions budgets described in Table 8-1 are not effective. The EPA had previously rejected all proposed state implementation plans for PJM states.

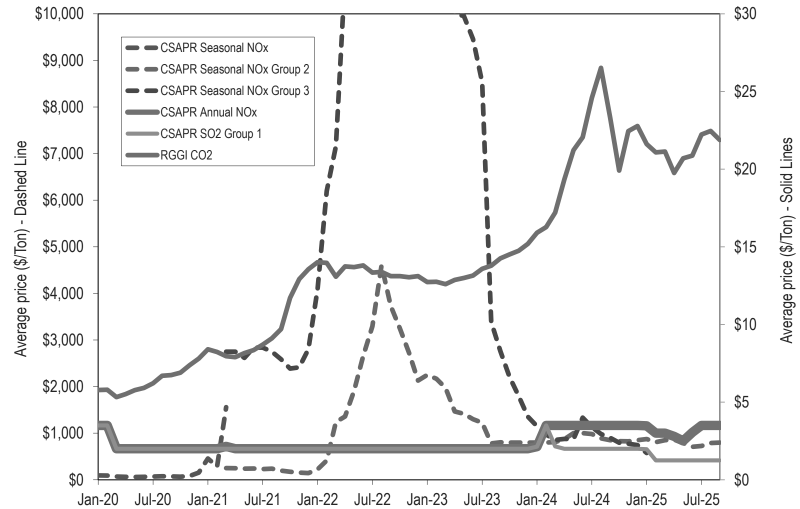
41 Wisconsin v. EPA, 938 F.3d 303, 318-20 (D.C. Cir. 2019).
42 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
43 See *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Docket No. EPA-HQ-OAR-2021-0668; FRL 8670-01-OAR, 87 Fed. Reg. 20036 (April 6, 2022).
44 See *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality*, Final Rule, EPA-HQ-OAR-2021-0668.
45 *Id.* at 35 (Table I.B-1).
46 *See Reconsideration of the National Ambient Air Quality Standards for Particulate Matter.* Proposed Rule, Docket No. EPA-HQ-OAR-2015-0072; FRL-8635-01- OAR, 89 Fed. Reg. 16202 (March 6, 2024).
47 Ohio v. EPA, Slip Op. No. 23A349. (S. Ct. June 27, 2024).

The new EPA Administrator has indicated plans to terminate the Good Neighbor Plan and revive negotiation of state implementation plans with the affected states.[48] Specific proposals are pending, and likely to result in litigation.

Figure 8-1 shows average, monthly settled prices for NO_X and SO_2 emissions allowances including CSAPR related allowances for 2020 through June 2025. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

The RGGI CO_2 allowance price averaged $21.30 in the first nine months of 2025, a 2.8 percent increase in comparison with the average price for the first nine months of 2024. The CSAPR annual NO_X allowance price averaged $3.15 in the first nine months of 2025, a 6.0 percent decrease in comparison with the average price for the first nine months of 2024. The group 2 CSAPR Seasonal NO_X allowance price averaged $800.46 in the first nine months of 2025, a 10.0 percent decrease in comparison with the average price for the first nine months of 2024.[49] The components of real-time LMP analysis shows that NO_x cost contributed $0.07 to the load-weighted average real-time LMP in the first nine months of 2025, compared to $0.11 in the first nine months of 2024.[50] CO_2 cost (RGGI) contributed $2.08 to the load-weighted average real-time LMP in the first nine months of 2025, compared to $1.91 in the first nine months of 2024.[51]

Figure 8-1 Spot monthly average emission price comparison: January 2020 through September 2025[52]



CAA: NSR

The CAA's NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.[53] NSR requires permits before construction commences. In PJM, permits are issued by state environmental regulators, or in a process involving state and regional EPA regulators.[54]

48 March 12th EPA Deregulation Notice; Fact Sheet, Good Neighbor Plan (GNP) Powering the Great American Comeback Fact Sheet (March 12, 2025), which can be accessed at: <https://www.epa.gov/system/files/documents/2025-03/good-neighbor-plan_powering-the-great-american-comeback_fact-sheet.pdf>.
49 Tennessee is the only PJM state that remains in the CSAPR NOX Ozone Season Group 2 Trading Program.
50 See Components of LMP in the *2025 Quarterly State of the Market Report for PJM: January through September*, Section 3: Energy Market.
51 Id.
52 The CSAPR Seasonal NOx Group 3 price peaked at an average price of $44,826 in March, 2022.
53 42 U.S.C § 7470 et seq.
54 CAA permitting in EPA Region 2 (New Jersey) is the responsibility of the state's environmental regulatory authority; CAA permitting in Region 3 (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) is the shared responsibility of each state's environmental regulatory authority and EPA Region 3; CAA permitting in Region 4 (Kentucky and North Carolina) is the shared responsibility of each state's environmental regulatory authority and EPA Region 4; CAA permitting in EPA Region 5 (Illinois, Indiana, Michigan and Ohio) is the responsibility of each state's environmental regulatory authority.

NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units.[55] The first part considers whether a modification would cause a significant emission increase of a regulated NSR pollutant. The second part considers whether any identified increase is also a significant net emission increase.[56]

CAA: RICE

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter.[57] These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM.

EPA regulations require that RICE that do not meet the EPA emissions standards (stationary emergency RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations.[58] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

Up to 50 hours of the maximum 100 hours can be operated in limited non emergency conditions.[59] By letter issued February 27, 2025, EPA indicated, in response to an inquiry from Duke Energy, that RICE can be operated for up to 50 hours per year to prevent the interruption of power supply in a local area when under an EEA1 and transition to EEA2 is likely without further action.[60]

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. Some DR registrations reflect a participant's reliance on behind the meter generation having environmental restrictions that limit the resource's ability to operate only in emergency conditions. PJM's DRHUB does not explicitly identify RICE generators, only whether it is an internal combustion engine. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register as DR individually or in portfolios. Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate. The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the

55 40 CFR § 52.21.
56 *Id.*
57 See *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, EPA–HQ–OAR–2008–0708, 78 Fed. Reg. 6674 (January 30, 2013); 40 CFR Parts 60 and 63.
58 Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <https://www.nerc.com/pa/Stand/Reliability%20 Standards/EOP-011-1.pdf> (Accessed March 2, 2020).

59 See 40 CFR 63.6640(f)(4)(ii) (RICE located at area sources of hazardous air pollutants (HAP)1 can operate for up to 50 hours per year in non-emergency situations to supply power as part of a financial arrangement with another entity). The following conditions must be met: (i) The engine is dispatched by the local balancing authority or local transmission and distribution system operator. (ii) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. (iii) The dispatch follows reliability, emergency operation or similar protocols that follow specific North American Electric Reliability Corporation (NERC), regional, state, public utility commission or local standards or guidelines. (iv) The power is provided only to the facility itself or to support the local transmission and distribution system. (v) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.
60 EPA letter to Duke Energy <https://www.epa.gov/system/files/documents/2025-05/response-to-duke-energy.pdf>. The EPA describes Duke's program: "the Mandatory 50 program is deployed when forecasted grid reserves fall below Duke Energy's thresholds for maintaining reliable service—specifically, under Energy Emergency Alert (EEA) Level 1 when transition to EEA Level 2 is imminent without further action. The program would fall below other emergency demand response programs in Duke Energy's resource stack and is constrained to 50 hours per calendar year. The letter states that the program prevents the need for rotating load shed, which would create local disturbances that could result in use of all generators throughout the affected areas."

capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations.

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[61] [62]

Executive Order 14057 requires the federal government to achieve "100 percent carbon pollution-free electricity on a net annual basis by 2030, including 50 percent 24/7 carbon pollution-free electricity by 2030."[63]

On April 25, 2024, the EPA finalized a rule taking four actions under CAA § 111(a)(1) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs) ("Carbon Emissions Rule").[64] The Carbon Emissions Rule repeals the Affordable Clean Energy (ACE) Rule; finalizes emission guidelines for GHG emissions from existing coal fired and oil/gas fired steam generating EGUs; revises the New Source Performance Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs; and revises the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The rule deferred action on emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines.

On May 9, 2024, a coalition of PJM states including West Virginia, Indiana, Kentucky, Tennessee, Virginia, and 20 other states, filed a petition for review of the Carbon Emissions Rule by the United Stated Court of Appeals for the D.C. Circuit.[65] PJM joined other RTOs to file an amicus brief in support of petitioners, arguing that the result would result in premature retirements of fossil generation and threaten reliability.[66] The states also sought to stay implementation of the rule, but the motion for stay was denied by the U.S. Supreme Court by order issued October 4, 2024.[67] The petition remains pending at the D.C. Circuit.

On June 11, 2025, the EPA proposed to repeal all GHG emissions standards for fossil fuel-fired power plants.[68] The EPA is further proposing to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution.[69] The EPA is also proposing, as an alternative, to repeal a narrower set of requirements that includes the emission guidelines for existing fossil fuel fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines.[70]

CWA: WOTUS Definition

The Clean Water Act (CWA) applies to navigable waters, which are defined as waters of the United States (WOTUS).[71] [72] The definition of WOTUS is a threshold issue that determines the hydrological scope of the CWA's applicability. Over the past decade, attempts to define WOTUS have been repeatedly addressed by the Courts, and no durable definition has resulted.[73] Establishing a durable definition is important to the electric industry, which needs to plan for compliance with the CWA and related regulations.

61 See CAA § 111.

62 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

63 See Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability, Section 102(a)(i), Executive Order 14057 (December 8, 2021), <https://www.whitehouse.gov/briefing-room/presidential-actions/2021/12/08/executive-order-on-catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability/?utm_medium=email&utm_source=govDelivery>.

64 See *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, Proposed Rule, Docket No. EPA–HQ–OAR–2023–0072, 89 Fed. Reg. 39798 (May 9, 2024) ("Carbon Emissions Rule").

65 See West Virginia, et al. v. EPA, No. 24-1120, et al. (D.C. Circuit) at 1.

66 See Motion for Leave to File Brief of Midcontinent Independent System Operator, Inc., PJM Interconnection L.L.C., Southwest Power Pool, Inc., and Electric Reliability Council of Texas, Inc., as Amicus Curiae in Support of Petitioners, No. 24-1120, et al. (D.C. Circuit September 13, 2024).

67 See West Virginia, et al. v. EPA, No. 24A95, et al.

68 *See Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units*, Docket No. EPA-HQ-OAR-2025-0124; FRL-12674-01-OAR, 90 Fed. Reg. 25752 (June 17, 2025).

69 *Id.* at 25755.

70 *Id.* at 25768.

71 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) ("The term "navigable waters" means the waters of the United States, including the territorial seas.").

72 For more details, see the *2019 Annual State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."

73 See, e.g., Rapanos v. U.S., 547 U.S. 715 (2006); Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers, 531 U.S. 159 (2001); U.S. v. Riverside Bayview Homes, Inc., 474 U.S. 121 (1985).

The scope of the CWA expanded as a result of an April 23, 2020, decision of the U.S. Supreme Court in *County of Maui v. Hawaii Wildlife Fund*, which held that the discharge of pollutants via groundwater requires a CWA permit.[74] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[75] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[76] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[77] Additional litigation or administrative action may clarify the functional discharge analysis.[78] *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[79]

On December 30, 2022, the EPA and the Army Corps of Engineers announced a final rule revising the definition of WOTUS.[80] The Rule defines WOTUS to include: (i) traditional navigable waters, the territorial seas, and interstate waters; (ii) impoundments of WOTUS; (iii) tributaries to traditional navigable waters, the territorial seas, interstate waters, impoundments when the tributaries meet either the relatively permanent standard or the significant nexus standard; (iv) wetlands, including jurisdictional adjacent wetlands; and (v) intrastate lakes and ponds, streams, or wetlands that meet either the relatively permanent standard or the significant nexus standard.[81] The rule became effective on March 20, 2023, except that, due to preliminary injunctions issued in court proceedings challenging the rule, the rule did not become effective in 26 states, including PJM states Indiana, Ohio, Tennessee, Virginia, West Virginia, and Kentucky.

74 590 U.S. 165 (April 23, 2020).
75 *Id.*
76 *Id.* at 1.
77 *Id.* at 16 ("The difficulty with this approach, we recognize, is that it does not, on its own, clearly explain how to deal with middle instances. But there are too many potentially relevant factors applicable to factually different cases for this Court now to use more specific language. Consider, for example, just some of the factors that may prove relevant (depending upon the circumstances of a particular case): (1) transit time, (2) distance traveled, (3) the nature of the material through which the pollutant travels, (4) the extent to which the pollutant is diluted or chemically changed as it travels, (5) the amount of pollutant entering the navigable waters relative to the amount of the pollutant that leaves the point source, (6) the manner by or area in which the pollutant enters the navigable waters, (7) the degree to which the pollution (at that point) has maintained its specific identity. Time and distance will be the most important factors in most cases, but not necessarily every case.").
78 *Id.*
79 See *id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").
80 *See Revised Definition of "Waters of the United States,"* Final Rule, Docket No. EPA-HQ-OW-2021-0602; FRL-6027.4-01-OW, 88 Fed. Reg. 3004 (January 18, 2023)
81 See *id.* at 3005-6.

On May 25, 2023, a decision of the U.S. Supreme Court held that "jurisdiction over an adjacent wetland under the CWA" requires "first, … a relatively permanent body of water connected to traditional interstate navigable waters … and second, that the wetland has a continuous surface connection with that water, making it difficult to determine where the 'water' ends and the 'wetland' begins."[82] The Court's definition of adjacent wetlands significantly reduced the range of waters meeting that definition compared to the range covered in the December 30, 2022 rule.

On August 29, 2023, the EPA issued a final rule modifying its 2022 rule to define adjacent wetlands consistent with the Supreme Court holding, and it became effective on September 8, 2023.[83] On March 24, 2025, the EPA and the Army Corps of Engineers issued a memorandum in response to requests for further clarification on the definition of adjacent wetlands, stating: "[A]n interpretation of 'continuous surface connection' which allows for wetlands far removed from and not directly abutting covered waters to be jurisdictional as adjacent wetlands has the potential to violate the direct abutment requirement for 'adjacent wetlands' under the plurality's standard and now *Sackett's* endorsement of that standard.[footnote omitted] Therefore, any components of guidance or training materials that assumed a discrete feature established a continuous surface connection are rescinded."[84]

CWA: Effluents

The EPA regulates under its National Pollutant Discharge Elimination System (NPDES) permitting authority discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.[85] The regulations, Effluent Limitations Guidelines and Standards (ELGs), are national industry-specific wastewater regulations based on the performance of demonstrated wastewater treatment technologies.

82 See Sackett v. EPA, 598 U.S. 651 (2023).
83 See *Revised Definition of "Waters of the United States [Conforming],"* Final Rule, Docket No. EPA-HQ-OW-2023-0346; FRL-11132-01-OW, 88 Fed. Reg. 61964 (September 8, 2023).
84 See *WOTUS Notice: The Final Response to SCOTUS; Establishment of a Public Docket; Request for Recommendations*, Docket No. EPA-HQ-OW-2025-0093; FRL-12683-01-OW, 90 Fed. Reg. 13428.
85 See 40 CFR Part 423. For more details, see the *2019 Annual State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."

On June 9, 2022, the EPA proposed the Water Quality Certification Improvement Rule (WQCIR), which would expand the grounds on which states may condition or block, projects in federal permit proceedings.[86] The WQCIR would provide each state certifying agency a role in determining the "reasonable period of time" to review the request and encourage their adoption of an "activity as a whole" analytical approach that would consider the impacts of the entire project rather than just the specific discharge needing certification.[87]

The EPA has been implementing ELGs established in its 2015 and 2020 rules.[88] [89] The 2015 Rule established limitations and standards applicable to discharges from steam electric generating units from bottom ash (BA) transport water, flue gas desulfurization (FGD) wastewater, fly ash (FA) transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non chemical metal cleaning wastes. The 2020 Rule revised the limitations and standards for BA transport water and FGD wastewater, leaving the other limitations and standards in place. The 2020 Rule applied less stringent effluent limits to three new subcategories of units: High FGD flow plants, low utilization generating units, and generating units that will permanently cease the combustion of coal by 2028.

Units subject to the generally applicable limits had to comply with the 2020 Rule as soon as possible on or after October 13, 2021, but no later than December 31, 2025.[90]

Plants are required to inform regulators of their plans to comply with the new rule by upgrading their plants with pollution control equipment or committing to retiring their units by 2028.[91]

Executive Order 13990 called for review and improvement of the 2020 Rule.

On April 25, 2024, pursuant to CWA, the EPA issued a rule strengthening the 2015 and 2020 ELGs for coal-fired power plants ("2024 Effluents Rule").[92] The 2024 Effluents Rule would reduce discharges by an estimated 660–672 million pounds per year, including toxic and bio accumulative pollutants, such as arsenic, lead, mercury, selenium, chromium, and cadmium.[93]

This 2024 Effluents Rule establishes a zero discharge of pollutants limitation for three wastewaters generated at coal-fired power plants: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate.[94] The regulation also establishes numeric discharge limitations for mercury and arsenic for combustion residual leachate (CRL) that is discharged through groundwater and for a fourth waste stream, called legacy wastewater, that is discharged from certain surface impoundments.[95] The regulation also eliminates less stringent requirements for two subcategories of facilities (high flow facilities and low utilization energy generating units) that were contained in the 2020 regulation.[96]

The 2024 Effluents Rule allows additional time for compliance for some plants that have installed, or are in the process of installing, additional treatment technologies to meet the 2015 and 2020 ELGs.[97] The rule allows some plants to continue to meet the 2015 and 2020 ELGs while they are in the process of closing and converting to use other fuels such as natural gas.[98]

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[99] Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

86 See *Clean Water Act Section 401 Water Quality Certification Improvement Rule*, Proposed Rule, 87 Fed. Reg. 35318 (June 9, 2022).
87 *Id.* at 35343–35349.
88 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48- OW, 80 Fed. Reg. 67838 (November 3, 2015).
89 See *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020).
90 *Id.* at 64652.
91 85 Fed. Reg. 64650, 64679–82; 88 Fed. Reg. 18440 (March 29, 2023); 40 CFR § 423.19(f)(1).
92 See *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. EPA-HQ-OW-2009-0819; FRL-8794-01- OW, Final Rule, 89 Fed. Reg. 40198 (May 9, 2024) ("2024 Effluents Rule"); CWA §§ 301, 304, 306, 307, 308, 402 & 501.
93 *Id.* at 40198, 40203.
94 *Id.* at 40198.
95 *Id.* at 40252.
96 *Id.* at 40200.
97 *Id.*
98 *Id.* at 40246.
99 42 U.S.C. §§ 6901 *et seq.*

On April 17 2015, the EPA published a rule under Subtitle D of RCRA, the Coal Combustion Residuals rule (2015 CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[100] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that the EPA determines that they are ''at least as protective as'' the EPA CCR regulations.[101]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[102]

The 2018 CCRR Revisions provide for two types of alternative performance standards. The first type of standards allows a state director (if a state has an EPA approved CCR permit program) or the EPA (if no state program) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and during post closure care. The second type allows issuance of technical certifications by a state director in lieu of a professional engineer.

The 2018 CCRR Revisions revised the groundwater protection standards for health-based levels for four contaminants: cobalt at 6 mg/L; lithium at 40 mg/L; molybdenum at 100 mg/L and lead at 15 mg/L. Standards for other monitored contaminants follow the Maximum Contaminant Level (MCL) established under the Safe Water Drinking Act.

The 2018 CCRR Revisions extended the deadline for closing coal ash units in two situations: (i) detection of a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or (ii) inability to comply with the location restriction regarding placement above the uppermost aquifer. The exceptions in the 2018 CCRR to the standards in the 2015 CCRR and relaxation of the deadlines create a less stringent federal rule.

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.[103]

On July 29, 2020, the EPA finalized revisions to the CCR rule in compliance with the court orders ("Revised CCRR").[104] The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.[105]

In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in nonparticipating states, noticed February 20, 2020.[106] This proposal includes requirements for federal CCR permit applications, content and modification, as well as procedural requirements. The EPA would implement this permit program at CCR units located in states that have not submitted their own CCR permit program for approval. No PJM state has yet applied for EPA approval of its own CCR permit program.

The new EPA Administrator has indicated plans to prioritize expeditious state permit reviews and update the CCR permit program.[107]

100 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).
101 The Water Infrastructure Improvements for the Nation Act (WIIN Act).
102 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).
103 Utility Solid Waste Activities Group, et al. v. EPA, 901 F.3d 414 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. March 13, 2019).
104 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure*, EPA-HQ-OLEM-2019-0172; FRL-10002- 02-OLEM, 85 Fed. Reg. 53516 (August 28, 2020).
105 *Id.* at 53516-53517, 53536.
106 *See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Federal CCR Permit Program*, EPA-HQ-OLEM-2019-0361, 85 Fed. Reg. 9940 (February 20, 2020).
107 March 12th EPA Deregulation Notice.

State Environmental Regulation

State Coal Ash Regulations

In Virginia, the Waste Management Board amended the Virginia Solid Waste Management Regulations in December 2015, to incorporate the EPA's 2015 CCRR, and did not adopt the less stringent 2018 CCRR Revisions. On July 1, 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[108] Dominion is developing plans to remove coal ash ponds at power stations in the Chesapeake Bay Watershed. The removed coal ash must be recycled (at least 6.8 million cubic yards) or disposed of in a modern, lined landfill. The Virginia DEQ is addressing closing ash ponds under two types of environmental permits: wastewater discharge permits covering the removal of treated water from the ponds; or solid waste permits covering the permanent closure of the ponds.

Table 8-2 shows the compliance status of affected units with Virginia Solid Waste Management Regulations:[109]

108 Va. Code § 10.1-1402.03.
109 Virginia Department of Environmental Quality website: <https://www.deq.virginia.gov/permits/waste/coal-ash>.

Table 8-2 Compliance status of affected units with Virginia Solid Waste Management Regulations

Plant	CCR Compliance Status
Bremo Bluff Power Station	As of April 2020, ash has been removed from the East and West Ponds. Plans for closure by removal of ash from the remaining North Pond impoundment are under development and will be addressed by the Virginia DEQ in a separate future permitting action.
Chesapeake Energy Center	The facility is currently developing plans for closure by removal of ash from the landfill, historical area, and impoundment.
Chesterfield Power Station	Dominion Energy Virginia submitted the required solid waste permit application for closure by removal and groundwater monitoring of the Upper and Lower Ash Ponds in February 2020, and it is currently under review. The application outlines the removal of ash to either an offsite permitted landfill or offsite beneficial reuse. The application estimates that it will take approximately 13 years to complete closure by removal activities.
Clinch River Power Station	The ash pond was closed and capped prior to January 1, 2019. Clinch River Plant ceased burning coal in 2015 and no longer produces CCR material. The Plant now uses natural gas as fuel. All units are currently being monitored and maintained in post-closure care.
Clover Power Station	The station also has had a permitted CCR landfill since 1993. The permit is currently under revision to incorporate EPA CCR Rule requirements applicable to existing landfills.
Possum Point	The impoundments at this facility (coal ash ponds) are subject to the EPA CCR Rule and the requirements of Virginia Waste Management Act.

Effective April 21, 2021, in response to a statutory mandate,[110] the Illinois Environmental Protection Agency (Illinois EPA) promulgated rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[111] The proposed rules contain standards for the storage and disposal of coal combustion residuals in surface impoundments. The rules include a permitting program intended to meet federal standards.[112] The Illinois EPA identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.[113] The Illinois

110 Ill. Public Act 101-171 (a.k.a. SB 09).
111 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.
112 See *In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments*, No. R 2020-019 (March 30, 2020) at 1 (Proposed New 35 Ill. Adm. Code 845).
113 In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments, No. R 2020-019 (March 30, 2020) at 3 (Proposed New 35 Ill. Adm. Code 845z0.

EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[114]

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[115]

- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became law. CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis. The emissions caps are based on average emissions over a three year period from 2018 through 2020. The capped emissions are CO_2e and co-pollutants.[116] [117] New investor owned, gas fired units will have emissions caps after three years of operation. The resultant emissions caps are very low for some units and higher for others. More than 10,000 MW of capacity are currently affected, most of which have requested that the MMU calculate a unit specific opportunity cost. The MMU calculates opportunity costs for units that make requests and provide required data.

  CEJA includes provisions promoting the development of batteries and utility scale solar at the sites of up to five closed coal plants, two of which may be located in PJM. CEJA grants a subsidy of $110,000/MW for battery projects with at least 37 MW of capacity, capped at $28 million per year. A solar resource at a defined site may elect to receive either the battery subsidies or to sell premium RECs for $30 each.

- **New Jersey HEDD.** Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make investments in emissions reductions under the EPA transport rules. New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.

- **New Jersey Control and Prohibition of Carbon Dioxide Emissions.** On December 2, 2022, New Jersey implemented rules restricting new power plants to CO_2 emissions less than 860 pounds per megawatt hour, and banning sales of No. 4 and No. 6 fuel oil.[118] The rule limits existing electric generating units to no more than 1,700 lbs of CO_2 per megawatt hour of the gross energy input, by January 1, 2024, to no more than 1,300 pounds per megawatt hour by 2027, and to no more than 1,000 pounds per megawatt hour by 2035.

- **Climate Solutions Now Act of 2022.** One April 8, 2022, Maryland enacted a requirement for reduction of statewide greenhouse gas emissions by 60 percent from 2006 levels by 2031 and net-zero emissions by 2045.[119]

- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

Some states proposed legislation in 2024 designed to reduce or eliminate greenhouse gas and other emissions. The proposed legislation is summarized in Table 8-3.

114 *Id.*
115 For more details, see the *2019 State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."
116 Carbon dioxide equivalent (CO2e) emissions means the total emissions of six greenhouse gases (carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride). Co-pollutants mean the six criteria pollutants identified by the US EPA pursuant to the Clean Air Act: Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particle Pollution, and Sulfur Dioxide.
117 See Energy Transition Act, Public Act 102-0662, Section 90-55, which amends section 9.15 (k-5) FOR the Illinois Environmental Protection Act.
118 See N.J.A.C. 7:27F.
119 See Maryland SB 528.

Table 8-3 Summary of proposed environmental regulatory activity affecting PJM resources by jurisdiction

Jurisdiction	Bill/Docket No.	Environmental Regulatory Activity
Delaware	SB 205	153rd Gen. Assembly: Would require any entity seeking to begin the business of using 30 megawatts (MW) of electricity or greater to first obtain a Certificate to Operate (COP) from the Public Service Commission.
	HB 233	153rd Gen. Assembly: Act requires regulated utilities to establish a separate rate for large energy-use facilities that mitigates the risk of costs associated with expanding infrastructure and maintaining reliability in the face of growing demand from being shifted to residential, small business, and other electric customers.
Illinois	HB 3758/SB 2497	2025-2026/104th General Assembly: Bill requiring energy storage procurement and reforms to the grid interconnection process.
Indiana		No current activity.
Kentucky		No current activity.
Maryland		No current activity.
Michigan		No current activity.
New Jersey	S 222	2024-2025 Reg. Sess.: Bill would authorize regulation of greenhouse gas emissions under "Air Pollution Control Act (1954)" and "Global Warming Response Act."
	S 220	2024-2025 Reg. Sess.: Bill would establish Nuclear Power Advisory Commission.
	S 2816	2024-2025 Reg. Sess.: Requires electric public utilities to submit to BPU and to implement electric infrastructure improvement plans.
	S 4143	2024-2025 Reg. Sess.: Requires submission of energy usage plan to BPU for proposed artificial intelligence data centers; requires all electricity for artificial intelligence data centers to be derived from new clean energy sources.
	S 237	2024-2025 Reg. Sess.: Establishes 100 percent clean electricity standard and directs BPU to establish clean electricity certificate program.
	A 5902/S 4693	2024-2025 Reg. Sess.: Requires BPU to work with neighboring states to research and recommend certain action concerning electric capacity and transmission.
	SJR 154/AJR 216	2024-2025 Reg. Sess.: Directs BPU to investigate RPM; directs State to promote affordable energy practices and to urge PJM to implement certain reforms.
	S 4143/ A 5564	2024-2025 Reg. Sess.: Requires submission of energy usage plan to BPU for proposed artificial intelligence data centers; requires all electricity for artificial intelligence data centers to be derived from new clean energy sources.
	S 4289/A 5267	2024-2025 Reg. Sess.: Requires BPU to procure and incentivize transmission scale energy storage.
	S 237	2024-2025 Reg. Sess.: The "New Jersey Clean Energy Act of 2024" establishes 100 percent clean electricity standard and directs BPU to establish clean electricity certificate program.
	S 4570	2024-2025 Reg. Sess.: Withdraws New Jersey's participation in RGGI.
North Carolina		No current activity.
Ohio		No current activity.
Pennsylvania	HB 782	2025-2026 Reg. Sess.: Requires public utilities to report lobbying and political activities expenses to exclude them from rates; requires electric distribution companies to be in an RTO and to report voting in PJM processes.
Tennessee		No current activity.
Virginia		No current activity.
Washington, D.C.		No current activity.
West Virginia		No current activity.

Clean Energy Standards

- In April 2020, Virginia enacted the Virginia Clean Economy Act, which orders the closure of most coal generation in state by 2024, most fossil fuel generation by 2045, and adopts a 100 percent clean energy standard by 2045.[120] The legislation mandates Chesterfield Power Station Units 5 & 6 and Yorktown Power Station Unit 3 to be retired by the end of 2024, Altavista, Southampton and Hopewell to be retired by the end of 2028 and Virginia Power's remaining fossil fuel units to be retired by the end of 2045, unless the retirement of such generating units will compromise grid reliability or security.[121] The legislation also imposes a temporary moratorium on Certificates of Public Convenience and Necessity for fossil fuel generation, unless the resources are needed for grid reliability.[122]

Opportunity Cost

PJM generators are subject to environmental constraints that limit generation. These constraints are specified in the operating permits issued by the jurisdictional environmental authority. Schedule 2 of the PJM Operating Agreement provides that the opportunity cost associated with the environmental constraints may be included in a generator's cost-based offer.[123] Opportunity cost associated with a physical equipment limitation or a fuel supply limitation, under certain circumstances, may also qualify for inclusion in the cost-based offer.[124]

More than 10,000 MW of capacity are currently affected by CEJA, most of which have requested that the MMU calculate a unit specific opportunity cost. The CEJA operating limits have resulted in significant opportunity cost adders to cost-based energy market offers for affected units. The CEJA opportunity cost adders were 3.1

120 Va. HB 1526/SB 851.
121 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).
122 *Id.*
123 PJM Operating Agreement, Schedule 2,
124 Id. at 5(b).

times, on average, the opportunity cost adders associated with the operating permit constraints during the first nine months of 2025.

The MMU calculates opportunity costs for units that make requests and provide required data. The MMU calculated opportunity cost adders for 175 generators in the first nine months of 2025. The calculations are generally done one time per week and the resulting opportunity cost is effective for a seven day period. More frequent calculations are done in cases where the constraints are tight and the opportunity cost is expected to vary significantly from day to day.

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, Vermont and Virginia (as of January 1, 2021) to cap CO_2 emissions from power generation facilities.[125] Virginia withdrew from RGGI effective January 1, 2024.

Delaware, Maryland and New Jersey are members of RGGI, and Virginia was a member from January 1, 2021 through 2023. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[126] Virginia joined RGGI on January 1, 2021, and left RGGI on December 31, 2023. A decision issued November 18, 2024, by the Floyd County Circuit Court of Virginia determined that the Governor lacked the authority to remove Virginia from RGGI.[127] An appeal of the decision is pending in the Virginia Court of Appeals (Case No. 1494-23-4). Pennsylvania took action to join RGGI on April 23, 2022, but such action has been enjoined by court order on appeal.[128] [129] A decision on the merits of the appeal is pending at the Supreme Court of Pennsylvania.[130]

Table 8-4 shows the RGGI CO_2 auction clearing prices and quantities, in short tons and metric tonnes, for the 3rd control period through the 6th control period.[131] The clearing price for the auction held September 3, 2025, was \$22.25 per allowance (equal to one short ton of CO_2).[132] The Cost Containment Reserve (CCR) for 2025 was exhausted in the first auction of 2025 and all RGGI auctions held in 2025 have cleared above the CCR trigger price of \$17.03 per allowance.[133] All RGGI auctions in 2024 and the first two auctions of 2025 cleared above the CCR trigger price. The September 2025 auction clearing price increased11.6 percent from the last auction clearing price of \$19.93 in June 2025. The average RGGI auction price in the first nine months of 2025 was \$20.51 per allowance, a 1.5 percent increase over the average RGGI auction price in the first nine months of 2024.

125 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.
126 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc. (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.
127 See Association of Energy Conservation Professionals v. Virginia State Air Pollution Control Board, Case No. CL23000173-00.
128 CO2 Budget Trading Program, 52 Pa.B. 2471 (April 23, 2022), codified 25 Pa. Code Ch. 145; *see also* Executive Order–2019-07. Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.
129 See *Bowfin KeyCon Holdings, LLC v. Pennsylvania Department of Environmental Protection*, 347 M.D. 2022 (November 1, 2023) ("held that the Pennsylvania [DEP]'s CO2 Budget Trading Program Regulation is an unconstitutional tax, declared the rule to be void, and enjoined DEP from enforcing it"); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Memorandum Opinion, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 8, 2022); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Order Granting Application to Vacate, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 25, 2022).
130 See *Shirley v. Pennsylvania Legislative Reference Bureau* (No. 247 M.D. 2022); Supreme Court Docket Nos. 81 MAP 2022, 83 MAP 2022, or 85 MAP 2022.
131 Each control period is three years in duration. The 3rd control period covers 2015 through 2017. The 4th control period covers 2018 through 2020. The 5th control period covers 2021 through 2023. The 6th control period covers 2024 through 2026.
132 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).
133 RGGI auctions employ a price cap called the Cost Containment Reserve (CCR) trigger price. When demand for allowances exceeds the supply at the CCR trigger price, the auction is cleared by setting the price equal to the CCR trigger price and drawing on allowances that are held in reserve. In the March 2025 auction, the reserve allowances were not sufficient to meet the demand at the CCR trigger price and the auction cleared above the CCR trigger price. Since the CCR allowances for 2025 have been exhausted, the CCR trigger price of \$17.03 will not affect the remaining RGGI auctions in 2025.

Table 8-4 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th, 5th and 6th Control Periods[134]

	Short Tons				Metric Tonnes			
Auction Date	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold
March 11, 2015	$5.41	15,272,670		15,272,670	$5.96	13,855,137		13,855,137
June 3, 2015	$5.50	15,507,571		15,507,571	$6.06	14,068,236		14,068,236
September 9, 2015	$6.02	15,374,294	10,000,000	25,374,294	$6.64	13,947,329	9,071,850	23,019,179
December 2, 2015	$7.50	15,374,274		15,374,274	$8.27	13,947,311		13,947,311
March 9, 2016	$5.25	14,838,732		14,838,732	$5.79	13,461,475		13,461,475
June 1, 2016	$4.53	15,089,652		15,089,652	$4.99	13,689,106		13,689,106
September 7, 2016	$4.54	14,911,315		14,911,315	$5.00	13,527,321		13,527,321
December 7, 2016	$3.55	14,791,315		14,791,315	$3.91	13,418,459		13,418,459
March 8, 2017	$3.00	14,371,300		14,371,300	$3.31	13,037,428		13,037,428
June 7, 2017	$2.53	14,597,470		14,597,470	$2.79	13,242,606		13,242,606
September 8, 2017	$4.35	14,371,585		14,371,585	$4.80	13,037,686		13,037,686
December 8, 2017	$3.80	14,687,989		14,687,989	$4.19	13,324,723		13,324,723
March 14, 2018	$3.79	13,553,767		13,553,767	$4.18	12,295,774		12,295,774
June 13, 2018	$4.02	13,771,025		13,771,025	$4.43	12,492,867		12,492,867
September 9, 2018	$4.50	13,590,107		13,590,107	$4.96	12,328,741		12,328,741
December 5, 2018	$5.35	13,360,649		13,360,649	$5.90	12,120,580		12,120,580
March 13, 2019	$5.27	12,883,436		12,883,436	$5.81	11,687,660		11,687,660
June 5, 2019	$5.62	13,221,453		13,221,453	$6.19	11,994,304		11,994,304
September 4, 2019	$5.20	13,116,447		13,116,447	$5.73	11,899,044		11,899,044
December 4, 2019	$5.61	13,116,444		13,116,444	$6.18	11,899,041		11,899,041
March 11, 2020	$5.65	16,208,347		16,208,347	$6.23	14,703,969		14,703,969
June 3, 2020	$5.75	16,336,298		16,336,298	$6.34	14,820,045		14,820,045
September 2, 2020	$6.82	16,192,785		16,192,785	$7.52	14,689,852		14,689,852
December 2, 2020	$7.41	16,237,495		16,237,495	$8.17	14,730,412		14,730,412
March 3, 2021	$7.60	23,467,261		23,467,261	$8.38	21,289,147		21,289,147
June 2, 2021	$7.97	22,987,719		22,987,719	$8.79	20,854,114		20,854,114
September 8, 2021	$9.30	22,911,423		22,911,423	$10.25	20,784,899		20,784,899
December 1, 2021	$13.00	23,121,518	3,919,482	27,041,000	$14.33	20,975,494	3,555,695	24,531,190
March 9, 2022	$13.50	21,761,269		21,761,269	$14.88	19,741,497		19,741,497
June 1, 2022	$13.90	22,280,473		22,280,473	$15.32	20,212,511		20,212,511
September 7, 2022	$13.45	22,404,023		22,404,023	$14.83	20,324,594		20,324,594
December 7, 2022	$12.99	22,233,203		22,233,203	$14.32	20,169,628		20,169,628
March 8, 2023	$12.50	21,522,877		21,522,877	$13.78	19,525,231		19,525,231
June 7, 2023	$12.73	22,026,639		22,026,639	$14.03	19,982,237		19,982,237
September 6, 2023	$13.85	21,948,358		21,948,358	$15.27	19,911,221		19,911,221
December 6, 2023	$14.88	22,090,709	5,565,291	27,656,000	$16.40	20,040,360	5,048,749	25,089,108
March 13, 2024	$16.00	15,855,879	8,416,278	24,272,157	$17.64	14,384,216	7,635,121	22,019,337
June 5, 2024	$21.03	16,053,188		16,053,188	$23.18	14,563,211		14,563,211
September 4, 2024	$25.75	15,943,608		15,943,608	$28.38	14,463,802		14,463,802
December 4, 2024	$20.05	15,943,608		15,943,608	$22.10	14,463,802		14,463,802
March 12, 2025	$19.76	15,392,222	8,134,778	23,527,000	$21.78	13,963,593	7,379,749	21,343,341
June 4, 2025	$19.93	15,244,479		15,244,479	$21.97	13,829,563		13,829,563
September 3, 2025	$22.25	15,177,783		15,177,783	$24.53	13,769,057		13,769,057

134 See Regional Greenhouse Gas Initiative, "Auction Results," <https://www.rggi.org/auctions/auction-results>.

The RGGI auction held on September 3, 2025, generated $337.7 million in auction revenue. RGGI auctions have generated $9.7 billion in auction revenue since 2008.[135] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2022 reporting year, have invested $4.9 billion, 67.8 percent of auction revenues.[136] RGGI reports that 56 percent of the $4.9 billion was invested in energy efficiency, 12 percent on clean and renewable energy, seven percent on greenhouse gas abatement, 15 percent on direct bill assistance, five percent on beneficial electrification, six percent on administration and one percent on RGGI, Inc.[137]

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on 2024 CO_2 emission levels and the RGGI clearing price for the September 2025 auction ranges from $3.9 billion per year to $7.4 billion per year depending on associated reductions in carbon emission levels (Table 8-5).[138] Table 8-5 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2024 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-5 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2024 actual emissions level. States that

135 See Auction Results at <https://www.rggi.org/>.
136 *The Investment of RGGI Proceeds in 2023*, The Regional Greenhouse Gas Initiative (RGGI) at 16, July 2025, <https://www.rggi.org/investments/proceeds-investments>.
137 *Id.* at 15.
138 This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.

participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[139]

Table 8-5 Estimated CO_2 allowance revenue at June 2025 RGGI price level[140 141]

		Estimated CO_2 allowance revenue ($ millions), carbon price $22.25 per short ton						
Jurisdiction	2024 power generation CO_2 missions (million short tons)	5 percent reduction below 2024 emission levels	10 percent reduction below 2024 emission levels	15 percent reduction below 2024 emission levels	20 percent reduction below 2024 emission levels	25 percent reduction below 2024 emission levels	50 percent reduction below 2024 emission levels
Delaware	2.0	$43.1	$40.8	$38.6	$36.3	$34.0	$22.7
Illinois	28.9	$611.3	$579.1	$546.9	$514.7	$482.6	$321.7
Indiana	34.3	$725.2	$687.0	$648.9	$610.7	$572.5	$381.7
Kentucky	29.9	$631.5	$598.2	$565.0	$531.8	$498.5	$332.3
Maryland	9.5	$200.5	$190.0	$179.4	$168.8	$158.3	$105.5
Michigan	2.4	$50.2	$47.6	$45.0	$42.3	$39.7	$26.4
New Jersey	9.8	$208.0	$197.0	$186.1	$175.1	$164.2	$109.5
North Carolina	0.1	$2.2	$2.0	$1.9	$1.8	$1.7	$1.1
Ohio	77.1	$1,628.8	$1,543.1	$1,457.4	$1,371.7	$1,285.9	$857.3
Pennsylvania	74.8	$1,581.5	$1,498.2	$1,415.0	$1,331.8	$1,248.5	$832.4
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	30.8	$650.2	$616.0	$581.8	$547.6	$513.4	$342.2
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	48.2	$1,018.4	$964.8	$911.2	$857.6	$804.0	$536.0
Total	347.8	$7,350.8	$6,964.0	$6,577.1	$6,190.2	$5,803.3	$3,868.9

The RGGI emissions cap (carbon budget) is the sum of CO_2 allowances issued by each state. Table 8-6 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. The 2025 compliance year is the second year of the sixth control period.

In 2021, RGGI announced a third adjustment to the RGGI emissions cap to account for banked allowances from previous control periods.[142] [143] The first adjustment removed 57.4 million allowances that were banked or unused from the first control period. The reduction to the RGGI emissions cap was spread over a seven year period beginning in 2014 and ending with 2020.[144] A second cap adjustment, corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13.7 million allowances per year and was in place through 2020.[145] The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.[146] The base emissions cap for each of the next five years will be reduced by 19.1 million allowances. The percent

139 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/20190617a.shtml>.
140 The 2024 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from PJM generators.
141 Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-5 do not reflect offset allowances.
142 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.
143 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.
144 "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014) at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.
145 Id.
146 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

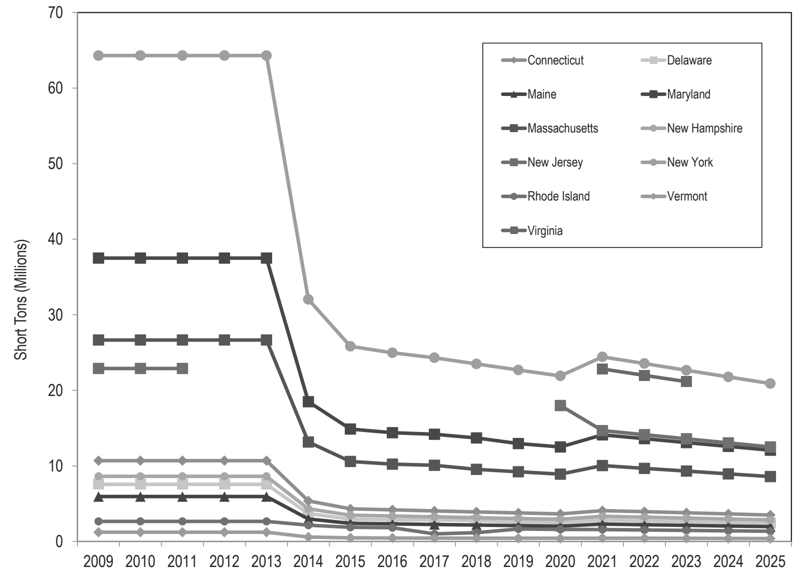
change columns in Table 8-6 show the year to year percent changes in the base RGGI cap and the adjusted RGGI cap.[147] The adjusted emissions cap for 2021 is the only year for which the adjusted carbon emissions cap increased.[148] Figure 8-2 shows the adjusted carbon budgets (CO_2 emissions caps) for the RGGI states.

Table 8-6 RGGI emissions cap history[149 150]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change in RGGI Cap	RGGI Adjusted Cap (short tons)	Percent Change in Adjusted Cap
2009	1st	$2.77	188,076,976		188,076,976	
2010		$1.93	188,076,976	0.0%	188,076,976	0.0%
2011		$1.89	188,076,976	0.0%	188,076,976	0.0%
2012	2nd	$1.93	165,184,246	0.0%	165,184,246	0.0%
2013		$2.92	165,184,246	0.0%	165,184,246	0.0%
2014		$4.72	91,000,000	(44.9%)	82,792,336	(49.9%)
2015	3rd	$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016		$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018	4th	$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019		$5.43	80,363,945	(2.3%)	58,472,538	(3.1%)
2020		$6.41	96,354,847	(2.5%)	74,463,439	(3.4%)
2021	5th	$9.61	119,767,784	(3.9%)	100,677,454	4.5%
2022		$13.46	116,112,784	(3.1%)	97,022,454	(3.6%)
2023		$13.58	112,457,784	(3.1%)	93,367,454	(3.8%)
2024	6th	$20.17	84,162,784	(3.2%)	69,401,609	(3.9%)
2025		$20.51	81,347,784	(3.3%)	66,586,609	(4.1%)

147 Percent changes for years with membership changes do not reflect the impacts of the change in membership. For example, the RGGI cap for 2020 reflects the impact of New Jersey rejoining RGGI in 2020 but the percent change from 2019 to 2020 does not include New Jersey's allowance budget. Virginia's adoption of RGGI in 2021 and Virginia's withdrawal at the end of 2023 are treated analogously.
148 The increase of 4.5 percent does not reflect the addition of Virginia as a RGGI state.
149 See Regional Greenhouse Gas Initiative, "Allowance Distribution" <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed April 21, 2025).
150 The increase in the RGGI Cap and the RGGI Adjusted Cap in 2020 is due to the reentry of New Jersey. The new cap is 18 million short tons higher than the previously published 2020 caps.

Figure 8-2 RGGI adjusted carbon budgets by state[151]



Carbon Pricing, State Revenues and Energy Market Prices

Table 8-7 shows the estimated allowance revenue for PJM states for carbon prices ranging from $20 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $16.5 billion if the carbon price were $50 per short ton and emission levels were five percent below 2024 levels. Allowance revenues to states would be $3.5 billion if the carbon price were $20 per short ton and emission levels were 50 percent below 2024.

151 Data for the figure was collected from allowance distribution reports available on the RGGI website <https://www.rggi.org/allowance-tracking/allowance-distribution>

Table 8-7 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
Jurisdiction	5 percent reduction below 2024 emission levels	10 percent reduction below 2024 emission levels	15 percent reduction below 2024 emission levels	20 percent reduction below 2024 emission levels	25 percent reduction below 2024 emission levels	50 percent reduction below 2024 emission levels
Carbon Price ($ per short ton)				$20.00		
Delaware	$38.8	$36.7	$34.7	$32.6	$30.6	$20.4
Illinois	$549.5	$520.5	$491.6	$462.7	$433.8	$289.2
Indiana	$651.9	$617.6	$583.2	$548.9	$514.6	$343.1
Kentucky	$567.6	$537.7	$507.9	$478.0	$448.1	$298.7
Maryland	$180.2	$170.7	$161.3	$151.8	$142.3	$94.9
Michigan	$45.2	$42.8	$40.4	$38.0	$35.7	$23.8
New Jersey	$186.9	$177.1	$167.3	$157.4	$147.6	$98.4
North Carolina	$1.9	$1.8	$1.7	$1.6	$1.5	$1.0
Ohio	$1,464.1	$1,387.1	$1,310.0	$1,233.0	$1,155.9	$770.6
Pennsylvania	$1,421.6	$1,346.7	$1,271.9	$1,197.1	$1,122.3	$748.2
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$584.5	$553.7	$523.0	$492.2	$461.4	$307.6
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$915.4	$867.2	$819.0	$770.8	$722.7	$481.8
Total	$6,607.5	$6,259.7	$5,912.0	$5,564.2	$5,216.4	$3,477.6
Carbon Price ($ per short ton)				$25.00		
Delaware	$48.4	$45.9	$43.3	$40.8	$38.2	$25.5
Illinois	$686.8	$650.7	$614.5	$578.4	$542.2	$361.5
Indiana	$814.8	$771.9	$729.1	$686.2	$643.3	$428.9
Kentucky	$709.5	$672.2	$634.8	$597.5	$560.1	$373.4
Maryland	$225.3	$213.4	$201.6	$189.7	$177.9	$118.6
Michigan	$56.5	$53.5	$50.5	$47.5	$44.6	$29.7
New Jersey	$233.7	$221.4	$209.1	$196.8	$184.5	$123.0
North Carolina	$2.4	$2.3	$2.2	$2.0	$1.9	$1.3
Ohio	$1,830.2	$1,733.8	$1,637.5	$1,541.2	$1,444.9	$963.2
Pennsylvania	$1,777.0	$1,683.4	$1,589.9	$1,496.4	$1,402.9	$935.2
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$730.6	$692.2	$653.7	$615.3	$576.8	$384.5
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,144.2	$1,084.0	$1,023.8	$963.6	$903.3	$602.2
Total	$8,259.4	$7,824.7	$7,390.0	$6,955.3	$6,520.6	$4,347.0
Carbon Price ($ per short ton)				$50.00		
Delaware	$96.9	$91.8	$86.7	$81.6	$76.5	$51.0
Illinois	$1,373.6	$1,301.3	$1,229.0	$1,156.7	$1,084.4	$723.0
Indiana	$1,629.7	$1,543.9	$1,458.1	$1,372.3	$1,286.6	$857.7
Kentucky	$1,419.0	$1,344.3	$1,269.7	$1,195.0	$1,120.3	$746.9
Maryland	$450.6	$426.9	$403.2	$379.4	$355.7	$237.1
Michigan	$112.9	$107.0	$101.0	$95.1	$89.1	$59.4
New Jersey	$467.3	$442.7	$418.1	$393.5	$368.9	$246.0
North Carolina	$4.8	$4.6	$4.3	$4.1	$3.8	$2.5
Ohio	$3,660.3	$3,467.7	$3,275.0	$3,082.4	$2,889.7	$1,926.5
Pennsylvania	$3,553.9	$3,366.9	$3,179.8	$2,992.8	$2,805.7	$1,870.5
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,461.2	$1,384.3	$1,307.4	$1,230.5	$1,153.6	$769.1
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,288.5	$2,168.0	$2,047.6	$1,927.1	$1,806.7	$1,204.5
Total	$16,518.8	$15,649.3	$14,779.9	$13,910.5	$13,041.1	$8,694.1

Table 8-8 shows the estimated impact of five different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $25.00 per tonne, the PJM load-weighted average LMP in the first nine months of 2025 would have increased by 0.7 percent.[152]

Table 8-8 Estimated impact of carbon price on LMP: January through September, 2024 and 2025

		2024 (Jan - Sep)			2025 (Jan - Sep)		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$34.31	$31.71	(7.6%)	$50.51	$48.88	(3.2%)
Scenario 2	$10.00	$34.31	$32.50	(5.3%)	$50.51	$49.38	(2.2%)
Scenario 3	$15.00	$34.31	$33.28	(3.0%)	$50.51	$49.87	(1.3%)
Scenario 4	$25.00	$34.31	$34.86	1.6%	$50.51	$50.87	0.7%
Scenario 5	$50.00	$34.31	$38.80	13.1%	$50.51	$53.36	5.7%

Table 8-9 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[153] [154] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.45 per MWh for a new combustion turbine (CT) unit, $16.85 per MWh for a new combined cycle (CC) unit and $43.12 per MWh for a new coal plant (CP). Table 8-11 and Table 8-12 show the carbon price impact ($ per MWh) for a range of heat rates and carbon prices for natural gas and coal fired generation.

Table 8-9 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.44	$4.89	$7.33	$24.45	$48.89	$97.79	$195.58
CC	$1.68	$3.37	$5.05	$16.85	$33.70	$67.40	$134.79
CP	$4.31	$8.62	$12.94	$43.12	$86.25	$172.49	$344.99

Table 8-9 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $187.50 per credit in the first nine months of 2025. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. The carbon price implied by the SREC price is slightly less than $400 per tonne. Table 8-9 shows that if the MWh produced by the solar resource resulted in avoiding the production of one MWh from a CT, the value of carbon reduction implied by an SREC price of $195.58 is a carbon price of $400 per tonne. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50.00 per tonne, assuming that a MWh from a CT is avoided, is $24.45 per MWh.

Applying this method to Tier I and Class I REC, and SREC price histories yields the implied carbon prices in Table 8-10. The carbon price implied by the average REC price for the first nine months of 2025 in Ohio is $10.24 per tonne which is less than half the average RGGI auction clearing price of $22.61 per tonne in the first nine months of 2025. The implied carbon prices for RECs in the other jurisdictions in Table 8-10 range from $49.24 per tonne to $65.23 per ton. The implied carbon price for Virginia RECs is $65.23, 2.9 times the average RGGI auction clearing price. The social cost of carbon is estimated to be in the range of $50 per tonne.[155] [156] The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The carbon prices implied by the SREC prices all exceed the carbon prices implied by the corresponding REC prices.

152 LMPs are recalculated to account for the defined cost of carbon emissions on marginal units' offer prices. The LMP calculation is not based on a counterfactual redispatch of the system to determine the marginal units and the marginal costs that would have occurred if all units had made all offers at short run marginal cost. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.
153 Heat rates from: *2024 Annual State of the Market Report for PJM*, Section 7: Net Revenue, Table 7-3.
154 Prices reflect carbon emissions rates from *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed May 7, 2024).
155 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.
156 A recent update by the EPA estimates the social cost of carbon emissions for 2030 to be between $140 and $380 per metric ton (2020 dollars). See Table ES.1 in Report on the Social Cost of Greenhouse Gases, U.S. Environmental Protection Agency (November 2023) <https://www.epa.gov/environmental-economics/scghg>.

Table 8-10 Implied carbon price based on REC and SREC prices: 2015 through September 2025

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jurisdiction with Tier I or Class I REC											
Delaware	$32.01	$33.01	$10.29	$11.60	$16.10	$19.94					
Maryland	$29.27	$26.17	$23.19	$21.35	$17.81	$19.98	$34.29	$37.82	$46.80	$49.98	$50.71
New Jersey	$25.37	$27.01	$24.08	$22.08	$19.25	$20.54	$31.62	$36.23	$48.37	$53.71	$60.30
Ohio	$8.54	$5.30	$6.29	$11.21	$14.04	$16.33	$14.93	$14.98	$13.04	$11.95	$10.24
Pennsylvania	$28.96	$26.43	$23.42	$21.53	$17.96	$20.06	$33.58	$37.76	$46.68	$52.12	$56.36
Virginia							$35.53	$36.02	$51.93	$63.36	$65.23
Washington, D.C.	$3.20	$4.05	$4.90	$4.69	$5.52	$20.25	$24.28	$27.49	$33.95	$47.28	$49.24
Jurisdiction with Solar REC											
Delaware	$85.66	$86.75	$35.80	$17.38							
Maryland	$251.99	$183.64	$128.05	$87.27	$84.19	$101.68	$121.11	$111.74	$104.44	$108.07	$104.99
New Jersey	$389.91	$425.49	$460.60	$446.35	$410.31	$394.18	$413.80	$424.70	$399.25	$396.30	$383.48
Ohio	$45.25	$36.26	$31.92	$21.73	$26.65						
Pennsylvania	$67.09	$55.22	$43.97	$28.16	$51.65	$63.80	$74.20	$83.02	$78.95	$72.84	$69.05
Washington, D.C.	$997.05	$996.49	$868.78	$842.89	$851.39	$869.41	$851.78	$856.50	$867.74	$794.15	$832.21
Regional Greenhouse Gas Initiative											
RGGI clearing price	$6.72	$4.93	$3.77	$4.86	$5.98	$7.06	$10.59	$14.84	$14.97	$22.23	$22.61

Table 8-11 Carbon price for natural gas fired generators[157]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
6,000	$3.17	$4.76	$6.35	$7.94	$9.52	$11.11	$12.70	$14.29	$15.87	$17.46	$19.05
6,500	$3.44	$5.16	$6.88	$8.60	$10.32	$12.04	$13.76	$15.48	$17.20	$18.92	$20.63
7,000	$3.70	$5.56	$7.41	$9.26	$11.11	$12.96	$14.81	$16.67	$18.52	$20.37	$22.22
7,500	$3.97	$5.95	$7.94	$9.92	$11.90	$13.89	$15.87	$17.86	$19.84	$21.83	$23.81
8,000	$4.23	$6.35	$8.47	$10.58	$12.70	$14.81	$16.93	$19.05	$21.16	$23.28	$25.40
8,500	$4.50	$6.75	$8.99	$11.24	$13.49	$15.74	$17.99	$20.24	$22.49	$24.74	$26.98
9,000	$4.76	$7.14	$9.52	$11.90	$14.29	$16.67	$19.05	$21.43	$23.81	$26.19	$28.57
9,500	$5.03	$7.54	$10.05	$12.57	$15.08	$17.59	$20.11	$22.62	$25.13	$27.65	$30.16
10,000	$5.29	$7.94	$10.58	$13.23	$15.87	$18.52	$21.16	$23.81	$26.45	$29.10	$31.75
10,500	$5.56	$8.33	$11.11	$13.89	$16.67	$19.44	$22.22	$25.00	$27.78	$30.56	$33.33
11,000	$5.82	$8.73	$11.64	$14.55	$17.46	$20.37	$23.28	$26.19	$29.10	$32.01	$34.92
11,500	$6.08	$9.13	$12.17	$15.21	$18.25	$21.30	$24.34	$27.38	$30.42	$33.47	$36.51
12,000	$6.35	$9.52	$12.70	$15.87	$19.05	$22.22	$25.40	$28.57	$31.75	$34.92	$38.10
12,500	$6.61	$9.92	$13.23	$16.53	$19.84	$23.15	$26.45	$29.76	$33.07	$36.38	$39.68
13,000	$6.88	$10.32	$13.76	$17.20	$20.63	$24.07	$27.51	$30.95	$34.39	$37.83	$41.27
13,500	$7.14	$10.71	$14.29	$17.86	$21.43	$25.00	$28.57	$32.14	$35.71	$39.29	$42.86
14,000	$7.41	$11.11	$14.81	$18.52	$22.22	$25.93	$29.63	$33.33	$37.04	$40.74	$44.44
14,500	$7.67	$11.51	$15.34	$19.18	$23.02	$26.85	$30.69	$34.52	$38.36	$42.20	$46.03
15,000	$7.94	$11.90	$15.87	$19.84	$23.81	$27.78	$31.75	$35.71	$39.68	$43.65	$47.62

157 Prices reflect uncontrolled carbon emission rates from Table A.3 in *Electric Power Annual*, EIA (October 19, 2023) <https://www.eia.gov/electricity/annual/>.

Table 8-12 Carbon price for coal fired generators[158]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
9,000	$8.39	$12.59	$16.78	$20.98	$25.17	$29.37	$33.57	$37.76	$41.96	$46.15	$50.35
9,500	$8.86	$13.29	$17.72	$22.14	$26.57	$31.00	$35.43	$39.86	$44.29	$48.72	$53.15
10,000	$9.32	$13.99	$18.65	$23.31	$27.97	$32.63	$37.30	$41.96	$46.62	$51.28	$55.94
10,500	$9.79	$14.69	$19.58	$24.48	$29.37	$34.27	$39.16	$44.06	$48.95	$53.85	$58.74
11,000	$10.26	$15.38	$20.51	$25.64	$30.77	$35.90	$41.03	$46.15	$51.28	$56.41	$61.54
11,500	$10.72	$16.08	$21.45	$26.81	$32.17	$37.53	$42.89	$48.25	$53.61	$58.97	$64.34
12,000	$11.19	$16.78	$22.38	$27.97	$33.57	$39.16	$44.76	$50.35	$55.94	$61.54	$67.13
12,500	$11.65	$17.48	$23.31	$29.14	$34.96	$40.79	$46.62	$52.45	$58.27	$64.10	$69.93
13,000	$12.12	$18.18	$24.24	$30.30	$36.36	$42.42	$48.48	$54.55	$60.61	$66.67	$72.73
13,500	$12.59	$18.88	$25.17	$31.47	$37.76	$44.06	$50.35	$56.64	$62.94	$69.23	$75.52
14,000	$13.05	$19.58	$26.11	$32.63	$39.16	$45.69	$52.21	$58.74	$65.27	$71.79	$78.32
14,500	$13.52	$20.28	$27.04	$33.80	$40.56	$47.32	$54.08	$60.84	$67.60	$74.36	$81.12
15,000	$13.99	$20.98	$27.97	$34.96	$41.96	$48.95	$55.94	$62.94	$69.93	$76.92	$83.92
15,500	$14.45	$21.68	$28.90	$36.13	$43.36	$50.58	$57.81	$65.03	$72.26	$79.49	$86.71
16,000	$14.92	$22.38	$29.84	$37.30	$44.76	$52.21	$59.67	$67.13	$74.59	$82.05	$89.51
16,500	$15.38	$23.08	$30.77	$38.46	$46.15	$53.85	$61.54	$69.23	$76.92	$84.62	$92.31
17,000	$15.85	$23.78	$31.70	$39.63	$47.55	$55.48	$63.40	$71.33	$79.25	$87.18	$95.10
17,500	$16.32	$24.48	$32.63	$40.79	$48.95	$57.11	$65.27	$73.43	$81.58	$89.74	$97.90
18,000	$16.78	$25.17	$33.57	$41.96	$50.35	$58.74	$67.13	$75.52	$83.92	$92.31	$100.70

State Renewable Portfolio Standards

Ten of 14 PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called eligible technologies. Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS must pay penalties (alternative compliance payments).

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[159] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of September 30, 2025, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of September 30, 2025, Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties. Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[160]

As of September 30, 2025, Kentucky, Tennessee and West Virginia had no renewable portfolio standards.

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information

158 Prices reflect carbon emission rates for refined coal in *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed May 7, 2024).

159 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed May 7, 2024).

160 See the Indiana Utility Regulatory Commission's "2021 Annual Report," at 37 (Oct. 2021) <https://www.in.gov/iurc/2981.htm>.

with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[161]

Beginning in March 2023, RECs for GATS generators will be hourly time stamped certificates.[162] Prior to March 2023, PJM EIS issued RECs based on how much a generator produced in a month.

Table 8-13 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year.

Table 8-13 Renewable and alternative energy standards of PJM jurisdictions: 2024 to 2034[163 164 165]

Jurisdiction with RPS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Delaware	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%	30.00%	32.00%	34.00%	37.00%
Illinois	23.50%	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Maryland	36.20%	38.00%	40.50%	44.00%	45.50%	52.00%	52.50%	52.50%	52.50%	52.50%	52.50%
Michigan	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%	52.50%	52.50%		
North Carolina	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%	33.00%	36.00%	39.00%	42.00%
Virginia (Phase II utilities)	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%	45.00%	49.00%	52.00%	55.00%
Washington, DC	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%	100.00%	100.00%

The Climate and Equitable Jobs Act (CEJA), which became effective on September 15, 2021 in Illinois, increased the RPS target percent from 25 percent by 2025 to 40 percent by 2030. CEJA also increased the quotas for RECs sourced from new wind and new photovoltaic resources, and made changes to eligible technologies and geographic restrictions. See Table 8-14 for details.

Updates to the Maryland RPS became effective on June 1, 2021. Maryland Senate Bill 65 changed the intermediate RPS target levels while maintaining the target of 50 percent renewable by 2030.[166] Part of the legislation was to eliminate resources fueled by black liquor as a Tier 1 eligible technology. Senate Bill 65 reduced the penalty for solar noncompliance from $100 per credit to $80 per credit, and extended the Tier 2 standard which was scheduled to expire with the 2020 compliance year.

161 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).
162 "PJM EIS to Produce Energy Certificates Hourly", PJM Environmental Information Services (February 13, 2023) <https://www.pjm-eis.com/-/media/about-pjm/newsroom/2023-releases/20230213-pjm-eis-to-produce-energy-certificates-hourly.ashx>.
163 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
164 The table reflects calendar year standards for Maryland, Washington, DC, Ohio, and North Carolina. The standards for the remaining jurisdictions are for compliance years that begin on June 1, CCYY and end on May 31 of the following year.
165 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
166 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

The Delaware General Assembly passed new RPS legislation on February 10, 2021. The new law updates the Delaware RPS targets from 25 percent in 2025 to 40 percent in 2035.[167] Additional details are provided in Table 8-14.

On April 11, 2020, the Virginia legislature passed a new law that replaced Virginia's current voluntary RPS with a mandatory RPS.[168] The new law requires by 2050 that 100 percent of energy sold by phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by phase II utilities must come from RPS eligible resources by 2045.[169] [170] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.[171] The Board of Public Utilities is directed to develop and provide an orderly transition to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030.

On May 18, 2021, Maryland enacted legislation doubling the limit on net metered capacity from 1,500 to 3,000 MW.[172] The legislation is expected to boost the installation of distribution level solar power.

On July 9, 2021, New Jersey enacted legislation establishing a new program for SRECs under the BPU.[173] Through the SREC-II program, the BPU distribute solar renewable certificates to qualifying solar power facilities. The legislation includes incentives for at least 1,500 MW of behind the meter solar facilities and 750 MW of community solar by 2026. It also includes a new competitive solicitation process to incentivize at least 1,500 MW of large-scale solar power facilities by 2026, and develops siting criteria for large-scale solar projects.

167 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
168 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
169 A phase I utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a phase II utility is an investor-owned incumbent electric utility that was bound by such a settlement (§ 56-585.1 of the Virginia Code).
170 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS
171 N.J. S. 2314/A. 3723.
172 Md. Code Ann § 7–306(d) & 7–306.2(g) (HB 569).
173 N.J. P.L.2021 (S. 2605/A 4554).

Table 8-14 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, DC.

Table 8-14 Recent changes in RPS rules[174 175 176 177 178 179 180]

Jurisdiction	Legislation	Effective Date	Summary of changes
Illinois	Climate and Equitable Jobs Act (Public Act 102-0662)	September 15, 2021	Updated the RPS target to 40.0 percent by 2030. The previous target of 25.0 percent by 2025 is still required. Updated the requirement for RECs from new wind generation from 2,000 GWH annually to 4,500 GWH beginning in the 2021/2022 delivery year; increasing to 20,250 GWH in 2030/2031. Updated the requirement for RECs from new photovoltaic generation from 2,000 GWH annually to 5,500 GWH beginning in the 2021/2022 delivery year; increasing to 24,750 GWH in 2030/2031. Removed tree waste as an energy source for eligible resources and added waste heat to power systems and qualified combined heat and power systems as eligible resources. Updated the geographic restrictions to allow RECs from utility scale wind or photovoltaic resources that are deliverable via high voltage direct current transmission.
Maryland	Senate Bill 65	June 1, 2021	Maintains theTier 1 target of 50.0 percent in 2030 with 14.5 percent solar carve out, but changes the intermediary target levels beginning in 2022. The alternatvie compliance payment for solar was reduced and the definition of Tier 1 resource now excludes generators fueled by black liquor. Extends indefinitely the Tier 2 target of 2.5 percent which was set to expire in 2020. Tier 2 resources are defined as hydroelectric power other than pumped storage.
Delaware	151st General Assembly Senate Bill 33	February 1, 2021	Increases the RPS target from 25.0 percent in 2025 to 40.0 percent in 2035. Sets the solar carve out requirement to 10.0 percent in 2035. Establishes intermediary target levels for total RPS and the solar carve out for compliance years 2026 through 2034. Lowered the solar alternative compliance payment (SACP) from $400 per credit to $150 per credit.
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermediate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

On January 20, 2025, the Trump Administration issued a Presidential Memorandum withdrawing "from disposition for wind energy leasing all areas within the Offshore Continental Shelf."[181] The withdrawal effectively puts on hold indefinitely the offshore wind projects in New Jersey and Maryland. On May 5, 2025, the Attorneys General of New Jersey and Maryland, along with the 16 other states, filed suit against the Trump Administration over the withdrawal of offshore leasing.[182 183]

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[184]

174 Illinois Climate and Equitable Jobs Act (Public Act 102-0662), Section 90-30 (September 15, 2021).
175 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
176 See Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
177 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
178 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <https://code.dccouncil.us/dc/council/laws/22-257.html>.
179 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
180 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
181 *Temporary Withdrawal of all Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects*, Presidential Memorandum (January 20, 2025) <https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/>.
182 State of New York v. Trump, Case NO. 1:25-cv-11221 (Dist. of Mass. May 5, 2025).
183 *Attorney General Platkin Sues Trump Administration for Halting Development of Wind Energy*, New Release of the Attorney General for the State of New Jersey (May 5, 2025) <https://www.njoag.gov/news/>.
184 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.

On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities (NJPBU) to create an OREC program targeting installation of at least 3,500 MW of offshore wind capacity by 2030 (plus 2,000 MW of energy storage capacity).[185] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500 MW by 2030 has since been replaced by a target of 7,500 MW by 2035.[186] The BPU opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Danish wind power developer Ørsted.[187] [188] Two more projects were approved on June 30, 2021. Ørsted was awarded a second project for offshore wind capacity of 1,148 MW and Atlantic Shores Offshore Wind was awarded a project for 1,510 MW.[189] On October 31, 2023, Ørsted announced that it was canceling two major offshore wind projects, Ocean Wind 1 (1,100 MW) and Ocean Wind 2 (1,148 MW), that were planned off the coast of New Jersey.[190] The Associated Press reported in May 2024 that the New Jersey and Ørsted reached a settlement that required Ørsted to pay New Jersey $125 million.[191]

On January 24, 2024, the NJBPU awarded 2,400 MW of offshore wind capacity to the Leading Light Wind project and 1,342 to Attentive Energy LLC.[192] The Leading Light Wind project is a partnership between Invenergy and energyRE.

On December 17, 2021, the Maryland Public Service Commission awarded ORECs in its Round 2 solicitation to the 846 MW Skipjack Wind 2 offshore project, owned by Skipjack Offshore Energy LLC, an Ørsted subsidiary, and to the 808.5 MW Momentum Wind offshore project, owned by US Wind Inc.[193] ORECs for Skipjack Wind 2 have a levelized price of $71.61; ORECs for Momentum Wind have a levelized price of $54.17.[194] Both projects are expected to become operational before the end of 2026.[195] In 2017, Round 1 ORECs were awarded to Deepwater Wind's 120-MW Skipjack Wind Farm, later acquired by Ørsted, and U.S. Wind's 248 MW project.[196] On January 25, 2024, Ørsted announced it "has withdrawn from the Maryland Public Service Commission Orders approving the Skipjack 1 and 2 projects," noting that the OREC prices in the orders "are no longer commercially viable."[197]

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.[198] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[199]

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the ten PJM jurisdictions with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources.[200] Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-15 shows the Tier

185 N.J. S. 2314/A. 3723.
186 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.
187 BPU Docket No. QO18080851.
188 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.
189 "NJPBU Approves Nation's Largest Combined Offshore Wind Award to Atlantic Shores and Ocean Wind II", New Jersey BPU Press Release (June 30, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210630.html>.
190 Ørsted, Ørsted ceases development of its US offshore wind projects Ocean Wind 1 and 2, takes final investment decision on Revolution Wind, and recognises DKK 28.4 billion impairments (October 31, 2023) <https://orsted.com/en/company-announcement-list/2023/10/oersted-ceases-development-of-its-us-offshore-wind-73751>.
191 "New Jersey and wind farm developer Ørsted settle claims for $125M over scrapped offshore projects", Associated Press (May 28, 2024).
192 "NJBPU Approves Over 3,700 MW of Offshore Wind Capacity in Combined Award", New Jersey BPU Press Release (January 24, 2024) <https://www.nj.gov/bpu/newsroom/2024/approved/20240124.html>.
193 "Ørsted, US Wind Triumph with 1.6 GW in Maryland Offshore Tender," Renewables Now (December 20, 2021) <https://renewablesnow.com/news/rsted-us-wind-triumph-with-1-6-gw-in-maryland-offshore-tender-766237/>.
194 *Id.*
195 *Id.*
196 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).
197 Skipjack Wind to be Repositioned for Future Offtake Opportunities, Ørsted (January 25, 2024) <https://orsted.com/en/media/news/2024/01/skipjack-wind-to-be-repositioned-for-future-offtak-815811>.
198 "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>.
199 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>.
200 New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.

I standards for PJM states.[201] All eligible technologies for the RPS standards in Table 8-15 satisfy the EIA definition of renewable energy.[202]

Table 8-15 Tier I / Class I renewable standards of PJM jurisdictions: 2024 to 2034[203]

Jurisdiction with RPS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Maryland	33.70%	35.50%	38.00%	41.50%	43.00%	49.50%	50.00%	50.00%	50.00%	50.00%	50.00%
New Jersey	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%	50.00%	50.00%		
Pennsylvania	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, DC	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%	100.00%	100.00%

Delaware, Illinois, Michigan, North Carolina, Virginia and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[204]

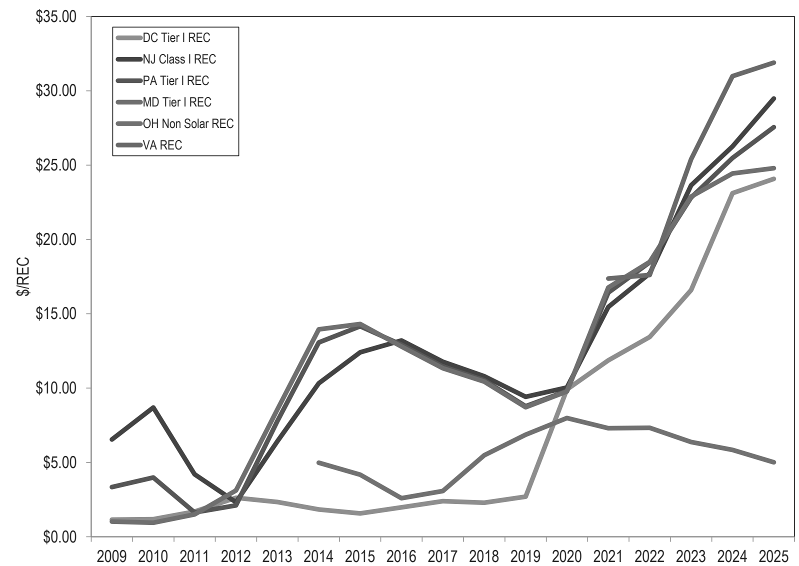
RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

PJM GATS makes data available for the amount of eligible RECs by jurisdiction. Eligible RECs are not the amount of actual RECs generated for that timeframe. A REC that is created may be eligible in multiple jurisdictions resulting in an over representation of generated RECs. This means if one REC is retired in Pennsylvania, the total amount of eligible RECs will reduce by more than one REC.

The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, DC, but in the other states REC prices are not publicly available.

Figure 8-3 shows the annual average Tier I REC price by jurisdiction from 2009 through September 2025. Tier I REC prices are lower than SREC prices. Several states have more stringent geographical restrictions for SRECs and higher alternative compliance payments (ACP) for SRECs than for RECs. For example, the average SREC price for the first nine months of 2025 in Washington, DC was $406.90 and the average Tier I REC price for the first nine months of 2025 in Washington, DC was $24.08. The DC RPS requires SRECs to be sourced from within DC while Tier I RECs may be sourced from anywhere within the PJM footprint. The DC solar ACP is $460 per SREC compared to $50 per REC for Tier I compliance.

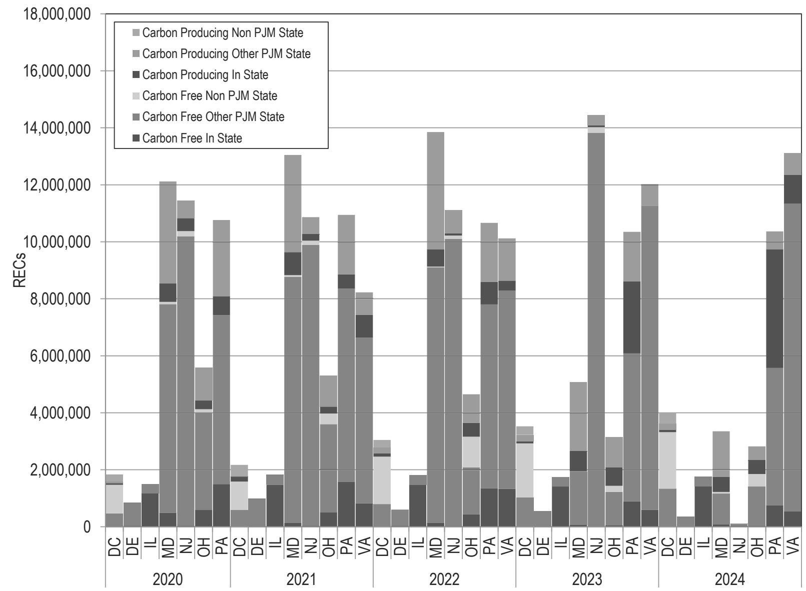
Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through September 2025



201 This includes New Jersey's Class I renewable standard.
202 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed May 7, 2024).
203 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
204 Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

Figure 8-4 and Table 8-16 shows the fulfillment of Tier I equivalent RPS requirement for 2019 through 2023 by state and by carbon producing and noncarbon producing RECs.[205] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon REC") or with landfill gas, captured methane, wood, black liquor, and other fuels. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The Illinois RPS, beginning in 2019, is fulfilled by noncarbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of in state, other PJM state and out of state carbon producing RECs and in state, other PJM state and out of state noncarbon RECs by state to meet the RPS requirements. In Table 8-16 the retired RECs are summarized by in state, other PJM state and non PJM state, and carbon producing RECs and noncarbon RECs. For example, Virginia met its 2024 RPS target using 4.1 percent carbon free RECs from Virginia, 82.3 percent carbon free RECs from other PJM states and 13.5 percent carbon producing RECs from Virginia and other PJM states. Ohio met its 2024 RPS target using 1.0 percent carbon free RECs from Ohio, 49.0 percent carbon free RECs from other PJM states, 15.6 percent carbon free RECs from non PJM states and 34.5 percent carbon producing RECs from Ohio and other PJM states. Illinois met its 2024 RPS target using 80.3 percent carbon free RECs from Illinois and 19.7 percent carbon free RECs from other PJM states. Illinois met its RPS target using 100.0 percent carbon free RECs for the 2019 through 2024 compliance years.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2020 through 2024



205 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear>. The timing of the REC retirement reports varies by state and the 2023 reporting year data is incomplete for some states.

Table 8-16 State fulfillment of Tier I equivalent RPS: 2020 through 2024

		Carbon Free REC				Carbon Producing REC			
Year	REC Type	In State	Other PJM State	Non PJM State	Total	In State	Other PJM State	Non PJM State	Total
2020	DE New Eligible	0.9%	99.1%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	25.5%	54.6%	80.1%	3.3%	2.8%	13.8%	19.9%
	OH Renewable Energy Source	10.5%	61.4%	2.0%	74.0%	5.5%	20.6%	0.0%	26.0%
	IL Renewable	78.3%	21.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	4.1%	60.4%	0.7%	65.1%	5.3%	29.6%	0.0%	34.9%
	NJ Class I	0.1%	89.1%	1.6%	90.7%	4.0%	5.3%	0.0%	9.3%
	PA Tier I	13.9%	55.1%	0.0%	69.0%	6.2%	24.8%	0.0%	31.0%
2021	DE New Eligible	0.3%	99.0%	0.0%	99.3%	0.7%	0.0%	0.0%	0.7%
	DC Tier I	0.0%	27.0%	45.9%	72.9%	7.4%	1.7%	17.9%	27.1%
	OH Renewable Energy Source	9.6%	58.3%	7.0%	74.9%	4.4%	20.7%	0.0%	25.1%
	IL Renewable	81.0%	19.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.0%	66.2%	0.5%	67.7%	6.1%	26.1%	0.0%	32.3%
	NJ Class I	0.1%	91.0%	1.4%	92.4%	2.0%	5.5%	0.0%	7.6%
	PA Tier I	14.4%	62.0%	0.0%	76.4%	4.6%	19.1%	0.0%	23.6%
	VA Renewable	10.0%	70.6%	0.0%	80.6%	9.7%	9.7%	0.0%	19.4%
2022	DE New Eligible	0.9%	99.1%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	26.0%	54.8%	80.8%	3.7%	6.8%	8.7%	19.2%
	OH Renewable Energy Source	9.3%	35.6%	23.0%	67.9%	10.5%	21.6%	0.0%	32.1%
	IL Renewable	81.3%	18.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.0%	64.7%	0.2%	65.9%	4.4%	29.7%	0.0%	34.1%
	NJ Class I	0.2%	90.7%	1.0%	92.0%	0.7%	7.4%	0.0%	8.0%
	PA Tier I	12.7%	60.4%	0.0%	73.1%	7.4%	19.4%	0.0%	26.9%
	VA Renewable	13.2%	68.8%	0.0%	81.9%	3.4%	14.7%	0.0%	18.1%
2023	DE New Eligible	0.9%	99.1%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	29.1%	53.9%	83.0%	2.2%	6.4%	8.5%	17.0%
	OH Renewable Energy Source	1.4%	37.5%	6.8%	45.7%	20.8%	33.5%	0.0%	54.3%
	IL Renewable	81.6%	18.4%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.2%	36.9%	0.2%	38.3%	13.9%	47.8%	0.0%	61.7%
	NJ Class I	0.1%	95.5%	1.4%	97.0%	0.5%	2.5%	0.0%	3.0%
	PA Tier I	8.6%	50.2%	0.0%	58.8%	24.5%	16.8%	0.0%	41.2%
	VA Renewable	5.0%	88.7%	0.0%	93.7%	0.0%	6.3%	0.0%	6.3%
2024	DE New Eligible	0.0%	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	33.2%	49.7%	82.9%	2.0%	5.4%	9.7%	17.1%
	OH Renewable Energy Source	1.0%	49.0%	15.6%	65.7%	17.3%	17.1%	0.0%	34.3%
	IL Renewable	80.3%	19.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	2.3%	32.3%	1.9%	36.5%	15.7%	47.8%	0.0%	63.5%
	NJ Class I	6.7%	81.1%	0.0%	87.8%	9.1%	3.1%	0.0%	12.2%
	PA Tier I	7.3%	46.5%	0.0%	53.8%	40.2%	6.0%	0.0%	46.2%
	VA Renewable	4.1%	82.3%	0.0%	86.5%	7.6%	5.9%	0.0%	13.5%

Table 8-17 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-17 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-17 are included in the total RPS requirements presented in Table 8-13. Maryland, New Jersey and Pennsylvania have Tier II or Class II standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. Washington, DC previously had Tier II standards. The Washington, DC tier II standard was discontinued at the end of the 2019 compliance year. By 2024, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste in 2020. Maryland established a minimum standard for offshore wind in 2017 that took effect in 2021 with an original requirement that 1.37 percent of load be served by offshore wind.[206] The standard has been revised to 0.14 percent for 2024.[207] The offshore wind requirement is only applicable if the Maryland offshore wind projects are producing RECs.[208]

206 Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2 <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.

207 See *Renewable Energy Portfolio Standard Report* at 5, Maryland Public Service Commissions (November 2023) <https://www.psc.state.md.us/wp-content/uploads/CY22-RPS-Annual-Report_Final-w-Corrected-Appdx-A.pdf>.

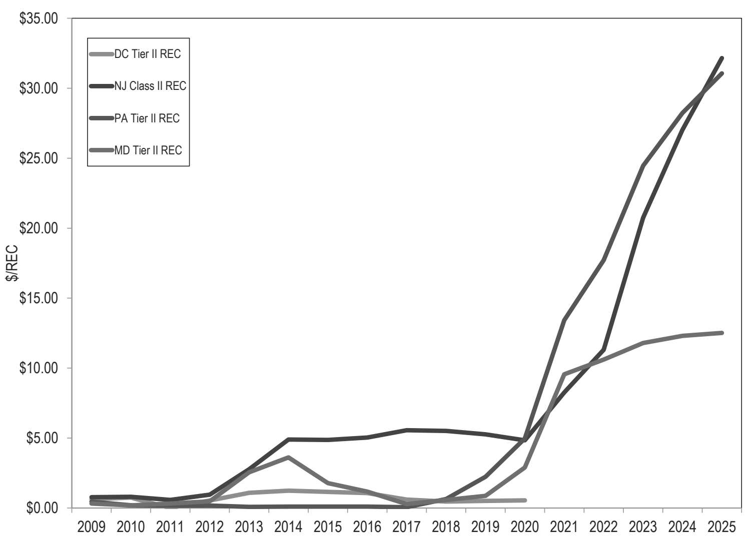
208 Id. at footnote 13.

Table 8-17 Additional renewable standards of PJM jurisdictions: 2024 to 2034[209]

Jurisdiction	Type of Standard	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Maryland	Off Shore Wind	0.14%	1.66%	2.61%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%
Maryland	Geothermal	0.15%	0.25%	0.50%	0.75%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Maryland	Tier 2	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Class II	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%		
North Carolina	Swine Waste	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (GWh)	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

Figure 8-5 shows the annual average Tier II REC price by jurisdiction for 2009 through September 2025. Tier II prices have been lower than Tier I REC prices in the past, but Pennsylvania and New Jersey Tier II REC prices are higher than their corresponding Tier I REC prices over the first nine months of 2025. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2025.[210] The average Pennsylvania Tier II REC price for the first nine months of 2025 was $31.06, 10.0 percent higher than the average price for 2024. The average New Jersey Class II REC price for the first nine months of 2025 was $32.15, 19.0 percent higher than the average price for 2024. The average Maryland Tier II REC price for the first nine months of 2025 was $12.51, 1.7 percent higher than the average price for the 2024.[211]

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through September 2025



209 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
210 The District of Columbia dropped Tier II RECs from their RPS in 2021.
211 Tier II REC price information obtained through Evolution Markets, Inc.

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-13 and Table 8-15 but must be met by solar RECs (SRECs). Table 8-18 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. The Illinois RPS specifies the number of RECs that must be sourced from photovoltaic resources energized after June 1, 2017. Recent legislation increased the SREC requirement from 2,000,000 RECs to 5,500,000 RECs beginning with the 2021/2022 Delivery Year.[212] New Jersey closed registration for new SRECs on April 30, 2020, having met its milestone that solar power equal or exceed 5.1 percent of New Jersey electricity sales.[213] On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for solar generators not eligible for New Jersey SRECs.[214] The new program establishes a 15 year fixed priced Transition REC (TREC). On July 28, 2021, New Jersey Board of Public Utilities approved the Successor Solar Incentive (SuSI) Program which will provide incentives for 3,750 MW of new solar generation by 2026.[215] Pennsylvania allows only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are Tier I resources in Pennsylvania. Ohio, Michigan and Virginia have no specific solar standards. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018, 5.1 percent for 2020 through 2022 and the solar standard decreases to 1.1 percent for 2032.[216] Maryland legislation in 2019 increased the solar carve out percentages from 2.5 percent to 14.5 percent in 2030. Ohio HB 6 removed the solar carve out from the Ohio RPS.[217] The Delaware General Assembly passed new RPS legislation on February 10, 2021 that increased the solar carve out target from 3.5 percent in 2025 to 10.0 percent in 2035.[218]

Table 8-18 Solar renewable standards by percent of electric load for PJM jurisdictions: 2024 to 2034[219] [220]

Jurisdiction with RPS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Delaware	3.25%	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%	5.80%	6.60%	7.40%	8.40%
Illinois (GWh)	5,500	5,500	5,500	5,500	5,500	5,500	24,750	24,750	24,750	24,750	24,750
Maryland	6.50%	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%	14.50%	14.50%	14.50%	14.50%
New Jersey	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%	1.40%	1.10%		
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, DC	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%	5.25%	5.50%	6.00%	6.50%

Figure 8-6 shows the annual average solar REC (SREC) price by jurisdiction for 2009 through the first nine months of 2025. The average NJ SREC price was $187.50 for the first nine months of 2025. The limited supply of solar facilities in Washington, DC compared to the RPS requirement results in higher SREC prices. The average Washington, DC SREC price was $406.90 for the first nine months of 2025, a 4.8 percent increase compared to the average DC SREC price for 2024.[221]

212 See amendments to Sec. 1-75(c)(1)(C) of the Illinois Power Agency Act contained in Section 90-30 of Public Act 102-0662.
213 See Clean Energy Act of 2019 (NJ AB-2723); N.J.A.C. 14:82.4(b)6; BPU, Monthly Report on Status toward Attainment of the 5.1 percent Milestone for Closure of the SREC Program (March 31, 2020).
214 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.
215 "NJBPU Approves 3,750 MW Successor Solar Incentive Program", New Jersey Board of Public Utilities Press Release (July 28, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210728.html>.
216 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.
217 Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
218 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
219 The Illinois solar standard currently requires 5.5 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 102-0662, September 15, 2021.
220 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
221 Solar REC average price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com>.

Figure 8-6 Average SREC price by jurisdiction: 2009 through September 2025

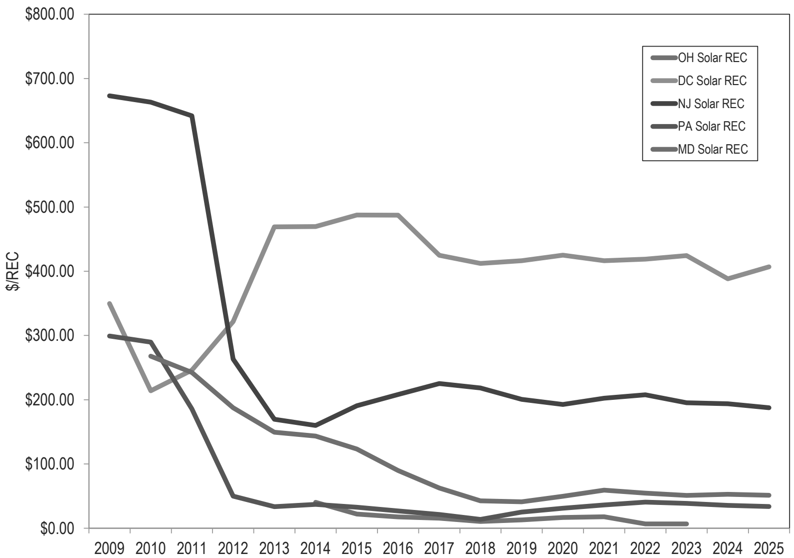


Figure 8-7 State fulfillment of Solar RPS: 2020 through 2024

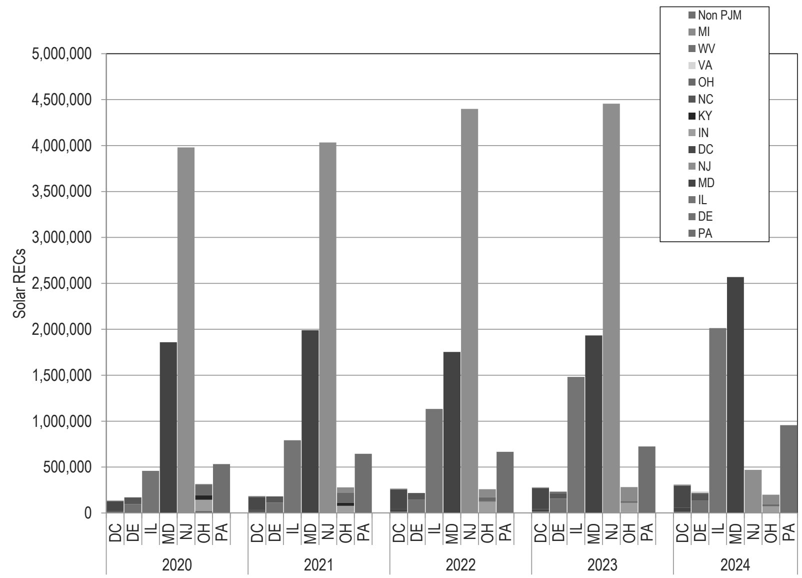


Figure 8-7 and Table 8-19 show where the SRECs originated that are used to satisfy the states' solar requirement for 2020 through 2024.[222] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-19 shows the percent of local SRECs, SRECs from other PJM states and SRECs from non PJM states used to meet the RPS requirements. Since 2020, all SRECs used for RPS compliance in Illinois, Maryland, Pennsylvania and New Jersey have been sourced from in state solar generators.

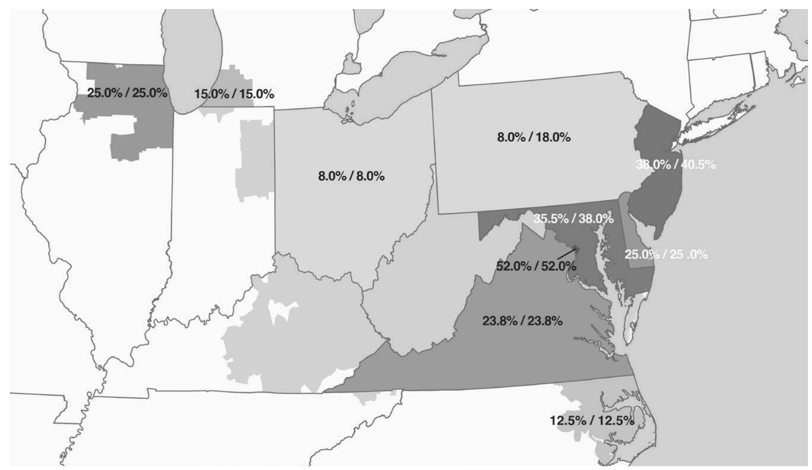
222 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReportsRPSRetiredCertificates ReportingYear> (Accessed October 17, 2025). The timing of the REC retirement reports varies by state and the 2024 reporting year data is incomplete for some states.

Table 8-19 State fulfillment of Solar RPS: 2020 through 2024

		In State	Other PJM State	Non PJM State
2020	DC Solar	81.5%	18.1%	0.4%
	DE Solar Eligible	56.7%	43.3%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	36.8%	63.2%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2021	DC Solar	78.0%	21.6%	0.3%
	DE Solar Eligible	62.3%	37.7%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	40.2%	59.8%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2022	DC Solar	81.9%	17.9%	0.2%
	DE Solar Eligible	65.8%	34.2%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	17.3%	82.7%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2023	DC Solar	82.2%	17.6%	0.3%
	DE Solar Eligible	67.0%	33.0%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	6.2%	93.8%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2024	DC Solar	78.0%	21.8%	0.2%
	DE Solar Eligible	56.8%	43.2%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	10.7%	89.3%	0.0%
	PA Solar	100.0%	0.0%	0.0%

Figure 8-8 shows the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. For each state in Figure 8-8, the first number represents the RPS percent for Tier I where defined, or renewable energy resources where tiers are not defined; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. The Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. As a result, the 18.0 percent number in Figure 8-8 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 8.0 percent number in Figure 8-8 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-8 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: 2025[223]



223 The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

Under the existing state renewable portfolio standards, 19.8 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first nine months of 2025. Tier I resources include landfill gas, run of river hydro, wind and solar resources. Tier II resources include pumped storage, large scale hydro, solid waste and waste coal resources. In the first nine months of 2025, only 9.5 percent of PJM generation was produced by renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-20. If the proportion of load among states remains constant, 25.4 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2030 under currently defined RPS rules. Approximately 17.5 percent of PJM load should have been served by Tier I or renewable energy resources in the first nine months of 2025. In the first nine months of 2025, only 7.6 percent of PJM generation was Tier I or renewable energy. The current REC production from PJM generation resources was not enough to meet the state renewable requirements for the first nine months of 2025, and LSEs purchased RECs from non PJM resources (e.g. behind the meter rooftop solar) and RECs from resources outside the PJM footprint (Table 8-21). LSEs that are unable to meet the RPS with RECs may use alternative compliance payments for unmet goals based on each state's requirements. If the proportion of load among states remains constant, 23.1 percent of PJM load must be served by Tier I or renewable energy resources in 2030 under defined RPS rules.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-20 shows generation by jurisdiction and resource type for the first nine months of 2025. Wind generation accounted for 22,206.8 GWh of the 50,380.7 Tier I GWh, or 44.1 percent. As shown in Table 8-20, 62,956.0 GWh were generated by Tier I and Tier II resources, of which Tier I resources accounted for 80.0 percent. Wind and solar generation (noncarbon producing) was 6.5 percent of total generation in PJM in the first nine months of 2025. Tier I generation was 7.6 percent of total generation in PJM and Tier II was 1.9 percent of total generation in PJM in the first nine months of 2025. Biofuel, landfill gas, pumped storage hydro, solid waste and waste coal (carbon producing) accounted for 12,875.4 GWh, or 20.5 percent of the total Tier I and Tier II generation.

Table 8-20 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through September, 2025

	Tier I							Tier II					
Jurisdiction	Biofuel	Landfill Gas	Run of River	Other Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Other Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	0.0	22.4	0.0	0.0	81.5	0.0	103.9	0.0	0.0	0.0	0.0	0.0	103.9
Illinois	0.0	37.0	0.0	0.0	176.3	10,583.2	10,796.5	0.0	0.0	0.0	0.0	0.0	10,796.5
Indiana	0.0	9.9	0.0	26.1	1,895.7	4,397.3	6,329.1	0.0	0.0	0.0	0.0	0.0	6,329.1
Kentucky	0.0	0.0	171.7	83.7	429.8	0.0	685.2	0.0	0.0	0.0	0.0	0.0	685.2
Maryland	0.0	25.2	0.0	0.0	770.6	601.3	1,397.1	0.0	0.0	885.1	0.0	885.1	2,282.2
Michigan	0.0	34.8	0.0	40.1	6.1	0.0	81.0	0.0	0.0	0.0	0.0	0.0	81.0
New Jersey	0.0	33.9	6.8	0.0	759.1	7.3	807.0	472.2	0.0	0.0	0.0	472.2	1,279.2
North Carolina	0.0	0.0	407.9	0.0	2,083.6	652.9	3,144.4	0.0	0.0	0.0	0.0	0.0	3,144.4
Ohio	0.0	55.2	618.1	0.0	6,354.0	2,002.2	9,029.5	0.0	0.0	0.0	0.0	0.0	9,029.5
Pennsylvania	0.0	173.5	3,447.6	15.1	1,335.3	2,664.9	7,636.4	2,229.7	0.0	103.7	4,953.3	7,286.7	14,923.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	931.6	265.2	587.5	39.4	6,445.0	35.6	8,304.3	2,215.5	1,310.5	0.0	0.0	3,526.0	11,830.3
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	22.0	600.4	0.0	181.8	1,262.1	2,066.3	0.0	0.0	0.0	405.3	405.3	2,471.7
Total	931.6	679.0	5,840.1	204.4	20,518.8	22,206.8	50,380.7	4,917.3	1,310.5	988.7	5,358.7	12,575.3	62,956.0

PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first nine months of 2025, Tier I generation in PJM met only 46.8 percent of the Tier I RPS requirements. Table 8-21 compares each state's RPS requirement for the first nine months of 2025 with generation by RPS eligible PJM generators. Illinois had sufficient in state generation to cover 62.5 percent of the RPS requirement and Pennsylvania generation was sufficient to cover 84.4 percent of the Tier I RPS requirement and 64.4 percent of the Tier II RPS requirement. North Carolina generation was 7.1 times higher than the RPS requirement in the first nine months of 2025; but a relatively small portion of the North Carolina load is in PJM. Overall there was sufficient generation by PJM generators to meet 46.8 percent of the Tier I RPS requirement and 90.4 percent of the Tier II RPS requirement for the first nine months of 2025. RPS compliance reports indicate that almost all of the RPS requirement is met with the purchase or acquisition of RECs, with only a very small amount of the requirement fulfilled through alternative compliance payments. A large portion of the Tier I RPS requirement is satisfied by behind the meter generation in the PJM states and to a lesser extent, through the purchase of RECs from non PJM states.

Table 8-21 RPS Requirements and Generation by RPS Eligible Resources: January through September, 2025

	Tier I			Tier II		
Jurisdiction	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement
Delaware	103.9	2,297.2	4.5%	0.0	0.0	
Illinois	10,796.5	17,262.7	62.5%	0.0	0.0	
Indiana	6,329.1	0.0		0.0	0.0	
Kentucky	685.2	0.0		0.0	0.0	
Maryland	1,397.1	16,583.7	8.4%	885.1	1,167.9	75.8%
Michigan	81.0	510.9	15.9%	0.0	0.0	
New Jersey	807.0	20,955.9	3.9%	472.2	1,434.9	32.9%
North Carolina	3,144.4	443.9	708.3%	0.0	0.0	
Ohio	9,029.5	10,099.1	89.4%	0.0	0.0	
Pennsylvania	7,636.4	9,050.1	84.4%	7,286.7	11,312.6	64.4%
Tennessee	0.0	0.0		0.0	0.0	
Virginia	8,304.3	26,555.5	31.3%	3,526.0	0.0	
Washington, D.C.	0.0	3,938.9	0.0%	0.0	0.0	
West Virginia	2,066.3	0.0		405.3	0.0	
Total	50,380.7	107,698.0	46.8%	12,575.3	13,915.4	90.4%

Table 8-22 shows the summer installed capacity rating of Tier I and Tier II wholesale capacity resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal, natural gas and oil units that qualify as Tier II because they have a secondary fuel capability that satisfies the alternative energy standards of a PJM state or jurisdiction. For example, a coal generator that can also burn waste coal to generate power could list the alternative fuel as waste coal. A REC is only generated when the unit is operating using the fuel listed as Tier I or Tier II. Ohio has the largest amount of solar capacity in PJM, 4,719.2 MW, or 28.8 percent of the total solar capacity. Wind resources located in western PJM, Illinois, Indiana and Ohio, account for 8,531.8 MW, or 72.7 percent of the total wind capacity.

Under the pre ELCC rules that were in effect up to the start of the 2023/2024 Delivery Year, a generator's capacity value was derated from the installed capacity level by multiplying the generator's net maximum capability by a derating factor. The derating factor was either based on the generator's historical performance during summer peak hours or a class average value calculated by PJM. The intent of the pre ELCC method was to obtain a MW value the generator can reliably produce during the summer peak hours.[224]

An average ELCC method was used to determine the capacity values for intermittent and storage resources for the 2023/2024 Delivery Year and the 2024/2025 Delivery Year.[225] Beginning with the 2025/2026 Delivery Year, PJM uses a marginal ELCC method to determine capacity values for all resources. As of September 30, 2025, the derated capacity for PJM capacity resources includes 2,265.7 MW of wind resources and 8,073.6 MW of solar resources. This compares to installed wind capacity of 11,862.8 MW in Table 8-33 and installed solar capacity of 13,515.3 MW in Table 8-37. Wind generators have higher derating factors during the winter months (November through April) because PJM rules make winter capacity interconnection rights (CIRs) available. The derated ICAP corresponding to wind capacity resources on March 31, 2025 was 3,594.8 MW. The decrease in the winter derated wind capacity from March 31, 2025 to September 30, 2025 is a result of winter CIRs that are provided

224 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
225 See Capacity Value of Intermittent Resources (ELCC) in *2024 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market.

to wind without charge for the winter months. PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. PJM should ensure that the winter capacity value of thermal resources is not inefficiently constrained by the failure to assign winter CIRs to thermal resources.

Table 8-22 Renewable capacity by jurisdiction (MW): September 30, 2025[226]

Jurisdiction	Biofuel	Coal / Biofuel	Hydro	Landfill Gas	Natural Gas / CMG	Natural Gas / Landfill Gas	Other Gas	Oil / Biofuel	Oil / Landfill Gas	Pumped-Storage Hydro	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Delaware	0.0	0.0	0.0	8.1	0.0	1,797.0	0.0	0.0	13.0	0.0	50.0	0.0	0.0	0.0	0.0	1,868.1
Illinois	0.0	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	136.3	0.0	0.0	0.0	5,135.7	5,287.0
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	0.0	1,464.3	0.0	0.0	0.0	2,350.5	3,826.1
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	289.0	0.0	0.0	0.0	0.0	421.7
Maryland	0.0	0.0	0.0	19.9	0.0	0.0	0.0	69.0	0.0	0.0	748.6	191.2	0.0	0.0	298.6	1,327.3
Michigan	0.0	0.0	13.9	12.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	30.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	11.0	33.9	0.0	0.0	0.0	0.0	0.0	453.0	763.4	204.6	0.0	0.0	4.5	1,470.3
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,658.6	0.0	0.0	0.0	397.0	2,380.6
Ohio	0.0	1,020.0	194.4	14.4	0.0	0.0	1.0	136.0	0.0	0.0	4,719.2	0.0	0.0	134.0	1,045.6	7,264.6
Pennsylvania	54.0	0.0	1,387.3	111.0	1,105.0	1,300.0	0.0	0.0	0.0	1,269.0	1,226.2	209.3	1,347.0	0.0	1,545.2	9,554.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	241.9	585.0	436.4	115.7	0.0	0.0	88.0	0.0	0.0	5,386.0	4,536.2	0.0	0.0	0.0	12.0	11,401.1
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	0.0	155.4	0.0	96.0	0.0	802.3	1,271.5
PJM Total	295.9	1,605.0	2,718.7	341.1	1,105.0	3,097.0	89.0	205.0	13.0	7,108.0	15,751.7	605.0	1,443.0	134.0	11,737.4	46,248.8

There were two pre ELCC classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent. There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.[227] For the 2023/2024 Delivery Year, the ELCC rating for solar generators with fixed panels was 50.0 percent, the ELCC rating for solar generators with tracking panels was 61.0 percent, and the ELCC rating for onshore wind generators was 15.0 percent.[228] For the 2024/2025 Delivery Year, the ELCC rating for solar generators with fixed panels was 33.0 percent, the ELCC rating for solar generators with tracking panels was 50.0 percent, and the ELCC rating for onshore wind generators was 21.0 percent. PJM implemented a new marginal ELCC approach for the 2025/2026 Delivery Year. For the 2025/2026 Delivery Year, the ELCC rating for solar generators with fixed panels is 10.0 percent, the ELCC rating for solar generators with tracking panels is 14.0 percent, and the ELCC rating for onshore wind generators is 38.0 percent.

Table 8-23 shows renewable capacity registered in the PJM generation attribute tracking system (GATS).[229] These resources are not PJM wholesale market resources even though most are located in PJM states. For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM wholesale market units. These nonwholesale resources include solar capacity of 14,180.5 MW of which 4,135.9 MW are in New Jersey. These nonwholesale resources can

226 "Renewable Generators Registered in GATS", PJM EIS <https://www.pjm-eis.com/reports-and-events/public-reports>. Capacity in ICAP.
227 Id.
228 *ELCC Class Ratings for 2023/2024 3IA, 2024/2026 BRA and 2026/2027 BRA*, PJM Interconnection, L.L.C. (January 6, 2023) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.
229 PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits. GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are also 2,953.0 MW of GATS capacity located in jurisdictions outside PJM that are eligible to sell RECs in at least one PJM jurisdiction.

Table 8-23 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): September 30, 2025[230]

Jurisdiction	Biofuel	Coal / Biofuel	Fuel Cell	Geothermal	Hydro	Landfill Gas	Natural Gas / CMG	Natural Gas / Distributed Generation	Other Gas	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Alabama	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Delaware	0.0	0.0	0.0	0.0	0.0	4.2	0.0	0.0	0.0	187.0	0.0	0.0	0.0	2.0	193.2
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	0.0	152.2	0.0	0.0	0.0	0.0	179.3
Illinois	0.0	0.0	0.0	0.6	20.0	43.8	0.0	0.0	2.2	2,435.4	0.0	0.0	0.0	548.8	3,050.7
Indiana	0.0	0.0	0.0	0.0	53.7	47.2	0.0	0.0	0.0	472.9	0.0	0.0	184.6	180.0	938.4
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	0.0	2.1	0.0	0.0	0.0	495.6	499.3
Kentucky	93.0	600.0	0.0	0.0	164.8	20.2	0.0	0.0	0.0	44.7	0.0	0.0	0.0	0.0	922.8
Maryland	18.5	0.0	0.6	93.2	0.4	4.0	0.0	0.0	0.0	1,892.4	10.0	0.0	0.0	0.3	2,019.3
Michigan	31.0	0.0	0.0	0.0	17.2	5.6	0.0	0.0	0.0	107.5	0.0	0.0	0.0	6.8	168.1
Minnesota	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,000.0	1,036.0
Missouri	0.0	0.0	0.0	0.0	0.0	5.6	0.0	0.0	0.0	61.2	0.0	0.0	0.0	693.0	759.8
New Jersey	0.0	0.0	2.4	0.0	0.0	9.5	0.0	0.0	15.4	4,135.9	0.0	0.0	0.0	3.1	4,166.2
New York	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
North Carolina	151.5	0.0	0.0	0.0	430.4	0.0	0.0	0.0	0.0	1,307.5	0.0	0.0	0.0	0.0	1,889.4
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	92.8	0.0	0.0	0.1	3.0	22.9	0.0	0.0	47.2	379.9	0.0	0.0	34.0	56.6	636.4
Pennsylvania	62.2	109.7	10.1	0.1	56.5	46.2	0.0	38.8	100.1	1,265.9	0.2	680.2	57.6	3.2	2,430.8
South Carolina	0.0	0.0	0.0	0.0	63.0	26.6	0.0	0.0	0.0	91.3	0.0	0.0	0.0	0.0	180.9
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	287.6	0.0	0.0	0.0	30.8	4.8	0.0	0.0	3.5	1,289.9	20.0	0.0	121.3	0.0	1,757.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	285.3	0.0	0.0	27.7	0.0	362.4
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	0.0	69.5	0.0	0.0	0.0	0.0	171.6
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.6
Total	835.1	709.7	13.1	94.0	997.7	269.2	0.0	38.8	217.8	14,180.5	30.2	680.2	425.2	3,349.4	21,841.0

Renewable energy credits are related to the production and purchase of wholesale power, but are not, when they constitute a transaction separate from a wholesale sale of power, subject to FERC regulation.[231] RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets. RECs revenues are included in net revenues in unit offers in the capacity market and the treatment of RECs in unit cost-based offers is included in unit fuel cost policies.

Delaware, North Carolina, Michigan and Virginia allow various types of resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[232] This is equivalent to providing a REC price equal to three times its stated value per MWh.

230 See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS>.
231 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.,* 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA… And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, … do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).
232 Delaware Code, Title 26, Chapter 1, Subchapter III-A, Section 356(a).

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina have created their own state tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must ultimately be traded. Table 8-24 shows the REC tracking systems used by each state within the PJM footprint. To ensure a REC is only used one time, REC tracking systems must keep an account of a REC from its creation until its retirement. A REC is considered to be retired when it has been used to satisfy an obligation associated with an RPS.

Table 8-24 REC tracking systems in PJM states with renewable portfolio standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Virginia	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		

All PJM states with renewable portfolio standards have established geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-25 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with each state's standards to be generated by in state resources. Illinois recently relaxed the geographic restrictions to allow RECs sourced from wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission. North Carolina has provisions that require RECs to be purchased from in state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions. Pennsylvania added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard to be sourced from resources located in Pennsylvania.

In addition, Pennsylvania and Virginia require that RECs used for RPS compliance be produced from resources located within the PJM footprint. Delaware requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

Table 8-25 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria or from utility scale wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Virginia	No	RECs must be purchased from resources located within PJM
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.

Alternative Compliance Payments

PJM jurisdictions have various methods for enforcing compliance with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, generally function as a cap on the market value of RECs, although in Pennsylvania the solar ACP is dependent upon the price of solar RECs retired during the year. In New Jersey, solar ACPs are currently $198 per MWh.[233] In Pennsylvania, the ACP for tier I and tier II RECs is $45 per MWh and the solar ACPs is 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates in other PJM states. The most recent ACP for Pennsylvania solar is $66.40.[234] Delaware recently reduced the solar ACP from $400 per credit to $150 per credit.[235] Maryland reduced the solar ACP from $100 per credit to $60 per credit effective June 1, 2021.[236] The Washington DC solar ACP was reduced from $480 per credit to $460 per credit for 2025.[237]

Figure 8-9 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. The public utility commissions in Michigan and North Carolina have discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

233 N.J. S. 2314/A. 3723.
234 See AEPS History Pricing report at the AEPS website <https://pennaeps.com/reports/> (Accessed May 2, 2025).
235 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
236 *Renewable Energy Portfolio Standard Report with Data for Calendar Year 2022* at 6, Maryland Public Service Commission (November 30, 2023) <https://www.psc.state.md.us/commission-reports/>.
237 DC Code: § 34-1434.

Table 8-26 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-26 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions for 2025[238] [239]

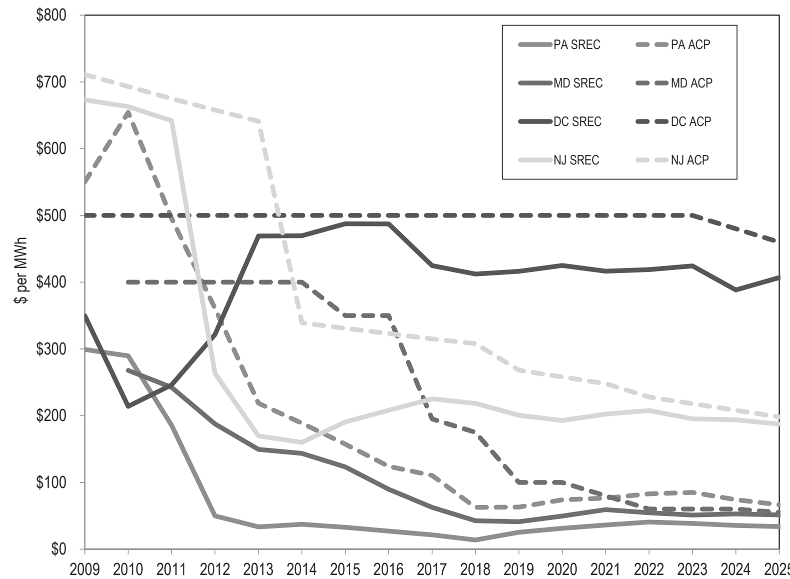
Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$150.00
Illinois	$0.35		
Maryland	$25.00	$15.00	$55.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$198.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$66.01		
Pennsylvania	$45.00	$45.00	$66.40
Washington, D.C.	$50.00	$10.00	$460.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission.

238 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2018 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.

239 The entry for Pennsylvania reflects the solar ACP for 2023. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed May 2, 2024).

Figure 8-9 Comparison of SREC price and solar ACP: 2009 through September 2025



In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public.

The Pennsylvania Public Utility Commission issued the 2023/2024 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in June 2025.[240] Pennsylvania reported that the 670,435 SRECs, 10,403,173 Tier I RECs and 13,403,664 Tier II RECs were retired during the 2023/2024 reporting year

240 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2023-24," (June 2025), <https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>

(June 1, 2023 through May 31, 2024). Supplier obligations for 776 SRECs, 16,044 Tier I RECs and 20,625 Tier II RECs required ACPs.

The Public Service Commission of the District of Columbia reported that 307,793 SRECs and 34,005,495 Tier I RECs were retired during the 2024 compliance year. The average price for solar RECs was $421. ACPs increased from $1.8 million for 2023 to $3.9 million for 2024.[241]

The Public Service Commission of Maryland reported that Tier 1 RECs retired for 2023 compliance decreased by 8.7 million RECs, or 63.4 percent, compared with 2022.[242] The report notes that the "ACP prices were in many instances less expensive than REC prices, and as a result suppliers chose to pay the ACP."[243] The total cost of compliance for 2023 was $564.2 million, a 28.6 percent increase over 2022.

The Public Utilities Commission of Ohio reported that 7,532,762 RECs were retired in the 2023 compliance year, which is 4.6 percent higher than the number of RECs retired in 2023.[244] Compliance cost for 2023 were $79.8 million, 17.9 percent higher than 2022.

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. The Delmarva report provides limited public information on RPS compliance cost.[245] Delmarva reports $13.0 million in ACPs but no other compliance cost information is available.

The Illinois Power Agency (IPA) reported delivery of ComEd RECs totaling 4,709,606 at an average price of $20.03 for the 2023/2024 RPS compliance year.[246]

241 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2024," Public Service Commission of the District of Columbia (May 1, 2025), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
242 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2023," Public Service Commission of Maryland (December 2, 2024) at 9, <https://www.psc.state.md.us/commission-reports/>.
243 Id. at 7.
244 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2023," Public Utilities Commission of Ohio (January 22, 2025), <https://puco.ohio.gov/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
245 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2022–May 31, 2023," Delmarva Power, (Sept. 29, 2023), <https://depsc.delaware.gov/rps-and-green-power-product-compliance/>.
246 "Annual Report Fiscal Year 2024" at 97, Illinois Power Agency (Feb. 18, 2025), <https://ipa.illinois.gov/about-ipa/ipa-publications.html>.

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2020 compliance report on August 10, 2021. The compliance report stated that Dominion met its general RPS requirement by purchasing 427,657 credits that consisted of wind and biomass RECs and energy efficiency credits (EECs).[247] Dominion met its solar requirement of 8,562 RECs, poultry waste requirement of 22,311 RECs, and swine waste requirement of 2,997 RECs through REC purchases. Dominion North Carolina's total REC requirements for 2020 increased 4.9 percent over 2019.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2020 standard by generating or acquiring 315,384 RECs.[248]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2024.[249] Electric power suppliers retired 14,449,269 class I RECs and 1,781,131 class II RECs. Suppliers submitted 298 class I ACPs and 54 class II ACPs at a cost of $50 per MWh. Electric power suppliers retired 3,156,170 solar RECs and 334,948 SACPs were submitted at a cost of $218 per MWh. Additionally, 958,816 transition RECs were retired and 341,632 SREC II were retired.[250] [251]

Table 8-27 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[252] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost of complying with RPS, as reported by the states, was $14.6 billion over the ten year period from 2014 through 2023 for the ten jurisdictions that had RPS and reported compliance costs.[253] The average RPS compliance cost per year based

247 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission (Oct. 1, 2021) at 41, <https://www.ncuc.gov/newsroom.html>.
248 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 15, 2022), <https://www.michigan.gov/mpsc/regulatory/reports/prior-renewable-reports>.
249 See EY22 RPS Compliance Results (2004 to 2022), New Jersey's Clean Energy Program (2023), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
250 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.
251 "NJBPU Approves 3,750 MW Successor Solar Incentive Program", New Jersey Board of Public Utilities Press Release (July 28, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210728.html>.
252 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.
253 The actual PJM RPS compliance cost exceeds the reported $14.6 billion due to incomplete data. The compliance cost data for Delaware, Michigan and North Carolina are not available for some years. Based on past data these states generally account for approximately 2 percent of the total RPS compliance cost of PJM states. The $14.6 billion cost also does not fully reflect the overhead and administrative costs associated with RPS programs.

on the reported compliance cost for the ten year period from 2014 through 2023 was $1.5 billion. The compliance cost for 2023, the most recent year with almost complete data, was $2.9 billion.

Table 8-27 RPS Compliance Cost[254 255 256 257 258 259 260 261 262 263 264]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916	$19,401,476	$21,133,971	$25,550,239		
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240	$8,121,914	$9,096,298	$9,567,891		
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676	$11,279,562	$12,037,673	$15,982,348		
Illinois	Total RPS	$19,900,679	$19,893,704	$23,538,303	$25,919,372	$25,775,523	$26,971,638	$34,726,109	$52,555,157	$73,185,068	$88,917,610
Maryland	Total RPS	$104,056,879	$126,752,147	$135,232,457	$72,064,102	$84,874,724	$142,275,744	$223,218,944	$409,846,140	$438,832,999	$564,208,521
	Solar	$29,388,337	$39,062,714	$45,556,987	$21,276,834	$27,352,183	$57,824,616	$122,973,787	$221,296,225	$187,244,056	$165,520,809
	Tier I	$70,677,220	$85,070,001	$88,234,024	$50,099,228	$56,473,113	$84,333,097	$99,836,397	$187,579,231	$247,158,373	$387,296,886
	Tier II	$3,991,322	$2,619,432	$1,441,446	$688,040	$1,049,428	$118,031	$408,760	$970,684	$4,430,570	$9,666,831
	Geothermal										$1,723,995
Michigan	Total RPS	$476,535		$3,264,504	$3,961,262	$3,264,504	$3,376,773	$5,379,970			
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	$653,810,457	$763,108,366	$970,177,803	$1,140,654,336	$1,236,035,486	$1,346,551,069
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	$560,509,712	$667,975,153	$822,247,072	$946,434,884	$959,987,769	$911,001,605
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	$83,474,335	$85,522,028	$130,272,633	$171,818,089	$241,810,299	$386,567,274
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	$9,826,410	$9,611,185	$17,658,099	$22,401,364	$34,237,418	$48,982,190
North Carolina	Total RPS	$297,513	$358,436	$317,644	$234,264	$442,579					
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	$50,214,523	$69,799,170	$81,752,397	$82,677,088	$67,708,887	$79,837,069
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092	$9,578,048	$0	$0	$0	$0
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431	$60,221,121	$81,752,397	$82,677,088	$67,708,887	$79,837,069
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911	$115,585,212	$99,681,713	$112,691,066	$182,995,718	$307,751,404	$461,430,587	$630,531,984
	Solar	$14,163,543	$19,227,690	$21,876,876	$17,987,722	$16,565,924	$20,608,103	$24,764,538	$27,673,083	$28,464,498	$26,306,505
	Tier I	$70,922,431	$94,339,032	$101,700,328	$95,370,456	$77,899,586	$74,780,310	$100,528,434	$159,457,100	$224,782,412	$292,270,379
	Tier II	$1,098,503	$1,020,210	$1,464,707	$2,227,034	$5,216,203	$17,302,653	$57,702,746	$120,621,222	$208,183,678	$311,955,100
Washington D.C.	Total RPS	$27,373,000	$38,541,000	$47,163,000	$42,700,000	$50,600,000	$57,300,000	$65,000,000	$99,100,000	$129,200,000	$168,600,000
	Solar	$25,145,000	$36,523,000	$44,898,000	$31,800,000	$42,800,000	$50,560,000	$59,200,000	$84,000,000	$106,600,000	$116,800,000
	Tier I	$2,141,000	$1,901,000	$2,131,500	$10,500,000	$7,600,000	$6,670,000	$5,800,000	$15,100,000	$22,600,000	$51,800,000
	Tier II	$87,000	$117,000	$133,500	$400,000	$200,000	$70,000	$0	$0	$0	$0
PJM	Total RPS	$676,652,857	$883,491,256	$984,039,969	$925,493,363	$987,005,938	$1,194,924,232	$1,584,384,913	$2,118,134,365	$2,406,393,026	$2,878,646,253

254 Several states have not released compliance reports for 2023.
255 "Retail Electricity Supplier's RPS Compliance Report," Delmarva Power (Sept. 28, 2022), <https://depsc.delaware.gov/rps-and-green-power-product-compliance/>
256 "Fiscal Year 2024 Annual Report," February 18, 2024, Illinois Power Agency (IPA), <https://ipa.illinois.gov/about-ipa/ipa-publications.html>.
257 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (December 2, 2024) at 9, <https://www.psc.state.md.us/commission-reports/>.
258 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 15, 2022, <https://www.michigan.gov/mpsc/regulatory/reports/prior-renewable-reports> The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.
259 "RPS Report Summary 2005-2024," New Jersey's Clean Energy Program, May 2025, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
260 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2023," Public Utilities Commission of Ohio, January 22, 2025, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
261 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2023-24," Pennsylvania Public Utility Commission, June 2025 <https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>
262 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2023," Public Service Commission of the District of Columbia, Executive Summary, May 1, 2024, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
263 "Application of Dominion Energy North Carolina for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance and Related Costs," Docket No. E-22, Sub 557, Sub 558, August 30, 2018 <https://www.ncuc.net/>. The North Carolina compliance cost entries reflects the compliance cost of Dominion Energy North Carolina.
264 The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.

Transco Regional Energy Access Expansion Project

By order issued January 11, 2023, FERC authorized a request filed by Transco to modify its gas pipeline system to increase its capacity by 829,400 Dth/d (.8 BCF/day) from the north east on its Leidy line to points in Pennsylvania, New Jersey and Maryland. Transco planned to have service available at the end of the fourth quarter of 2023.[265] In order to increase the capacity on the pipeline for this project Transco installed about 36 miles of new pipe, a new electric compressor station and modified five existing compressor stations. By letter dated July 26, 2024, FERC authorized Transco to commence service with facilities associated with the Regional Energy Expansion Project.[266] The 829,400 Dth/Day would be enough to supply about five combined cycle power plants.[267] On March 13, 2023, the New Jersey Division of Rate Counsel and New Jersey Conservation Foundation, et al., sought review in the United States Court of Appeals for the District of Columbia Circuit.[268] The appeal primarily argues that FERC ignored evidence that "clearly demonstrated that the state of New Jersey does not need and will not benefit from the Project's capacity."[269] On July 30, 2024, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the Certificate Orders.[270] On September 6, 2024, Transco filed an Application for Temporary Emergency Certificate so they could continue to provide service while this matter is resolved on remand.[271] Both PJM and the MMU submitted comments supporting the application.[272] On January 24, 2025, FERC issued an order reinstating authorization for Transco's Regional Energy Access Expansion Project.[273]

265 See 182 FERC ¶ 61,006 (2023), *order on reh'g*, 182 FERC ¶ 61,148 (2023), *order on reh'g*, 183 FERC ¶ 61,071 (2023).
266 See Letter: Authorization to Commence Service, FERC Docket No. CP21-94-000.
267 See *2023 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, "Table 7-55 Gas pipeline capacity need to replace units at risk of retirement." New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.
268 Case No. 23-1064, et al.
269 New Jersey Conservation Foundation, et al. v. FERC, Proof Opening Brief of Petitioners, Case No. 23-1064 (D.C. Cir July 26, 2023).
270 N.J. Conservation Foundation, et. al v. FERC, No. 23-1064 (July 30, 2024).
271 See FERC Docket No. CP21-94-004.
272 See PJM Interconnection, L.L.C.'s Comments in Support of the Application of Transcontinental Gas Pipe Line Company, LLC for a Temporary Emergency Certificate, FERC Docket No. CP21-94-004 (October 7, 2024); Comments of the Independent Market Monitor for PJM, FERC Docket No. CP21-94-004 (October 8, 2024).
273 See FERC Docket No. CP21-94-004.

Mountain Valley Pipeline

"On October 23, 2015, Mountain Valley Pipeline (MVP) filed an application with FERC for approval to construct own and operate MVP."[274] On October 13, 2017, MVP received a certificate of convenience and necessity from FERC. The pipeline is approximately 303 miles long stretching from the Equitrans Transmission system in Wentzel County West Virginia to Transco Zone 5 station 165 in Pittsylvania County Virginia. The capacity of the pipeline is approximately 2 BCF per day. On June 14, 2024, MVP entered service.[275] The 2,000,000 Dth/Day would be enough to supply about eleven combined cycle power plants.[276]

Transco Southeast Supply Enhancement

On May 24, 2024, Transcontinental Gas Pipe Line Company, LLC (Transco) filed a general project description draft of the proposed Southeast Supply Enhancement Project. This project is an expansion of the Transco system in southern Virginia, North Carolina, South Carolina, Georgia and Alabama. The total capacity will be 1,591,900 Dth/day from Transco Station 165 Zone 5 and the interconnection with Mountain Valley and points south to North Carolina, South Carolina, Georgia and Alabama. The proposal includes about 55 miles of new pipe and the addition of seven new compressors at existing compressor stations. The expected completion of the project is June 2028.[277] The 1,591,900 Dth/Day would be enough to supply about eight combined cycle power plants.[278]

Transco Commonwealth Energy Connector Project

On August 24, 2022, Transcontinental Gas Pipe Line Company, LLC (Transco) filed a certificate of public convenience and necessity to construct the Commonwealth Energy Connector Project.[279] The new capacity will be 105,000 Dth/d which Virginia Natural Gas, Inc. (VNG) has contracted for. This project

274 Mountain Valley Pipeline <https://www.mountainvalleypipeline.info/> (Accessed July 26, 2024).
275 Mountain Valley Pipeline <https://www.mountainvalleypipeline.info/> (Accessed July 26, 2024).
276 See *2023 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, "Table 7-55 Gas pipeline capacity need to replace units at risk of retirement." New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.
277 See Transcontinental Gas Pipe Line Company, LLC Southeast Supply Enhancement Project, Docket No. PF24-2-000, Draft Resource Reports 1-12 (May 24, 2024).
278 See *2023 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue: Table 7-55" New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.
279 See FERC Docket No. CP22-502.

is an expansion of the Transco system from Zone 5 Pooling point through Transco's South Virginia Lateral which interconnects between Transco and Columbia Gas Transmission, LLC. Additional compression, about 3.6 miles of additional pipe and modifications and installation of new facilities at the Emporia M&R station will be completed to increase the capacity. The project is expected to be completed by September 25, 2025. The 105,000 Dth per day would not be enough supply to run one combined cycle power plant [280]

Columbia Gas Transmission Virginia Reliability Project

On August 24, 2022, Columbia Gas Transmission LLC (Columbia) filed an abbreviated application for the authority necessary to construct and operate its Virginia Reliability project. The new capacity will be 100,000 Dth/d which Virginia Natural Gas, Inc. (VNG) has contracted for. This project will replace 49 miles of existing pipe, modifications at two compressor stations, modifications to one receipt point and delivery point increasing service to Market Area 34. This will allow VNG to receive gas at the Transco Columbia interconnection and deliver to VNG. This capacity is projected to be available by November 1, 2025.[281] The 100,000 Dth per day would not be enough supply to run one combined cycle power plant.[282]

Texas Eastern Transmission Appalachia to Market II Project

On July 7, 2022, Texas Eastern Transmission, LP (Texas Eastern) filed an abbreviated Application for a Certificate of Public Convenience and Necessity to develop the Appalachia to Market II Project. Prior to the filing, Texas Eastern conducted a binding open season for 55,000 Dth/d that will be made available based on improvements to the Texas Eastern system. The additional capacity will run from Appalachia supply basin in southwest Pennsylvania to New Jersey. Two compressor stations (reducing air emissions with upgraded compression equipment) will be replaced and two miles of looping of pipe will be added. PSEG Power LLC and Elizabethtown Gas signed up for the 55,000 Dth/d. The project is expected to be completed by November 1, 2025.[283] The 55,000 Dth per day would not be enough supply to run one combined cycle power plant.[284]

Eastern Gas Transmission and Storage Inc. Capital Area Project

On December 11, 2024 Eastern Gas Transmission and Storage (EGTS) filed an abbreviated Application for a Certificate of Public Convenience and Necessity to develop the Capital Area Project. The new capacity will be 67,500 Dth/d which Washington Gas Light Company (WGL) has contracted for. This project will increase EGTS capacity from the Leidy Area in Pennsylvania to points in Maryland and Virginia. Additional compression will be added at four compressor stations: Centre Compression Station, Chambersburg Compression Station, Leesburg Compression Station and Finnerfrock Compression Station. The expected completion date is November 1, 2027.[285] The 67,500 Dth/d would not be enough supply to run one combined cycle power plant.[286]

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[287] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[288] [289]

280 See *2023 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-55. New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.
281 See FERC Docket No. CP22-503.
282 See *2023 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-55. New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.
283 See FERC Docket No. CP22-486-000.
284 See *2023 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-55. New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.
285 See FERC Docket No. CP25-29-000.
286 See *2023 Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, Table 7-55. New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.
287 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 4, 2022).
288 On April 16, 2020, the EPA issued a revised final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed May 7, 2020).
289 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO_2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards,"<https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020)

Table 8-28 shows SO_2 emission controls by fossil fuel fired units in PJM.[290] [291] [292] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[293] Of the current 39,420.9 MW of coal capacity in PJM, 38,651.9 MW of capacity, 98.0 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-28 SO_2 emission controls by fuel type (MW): September 30, 2025[294]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	38,651.9	769.0	39,420.9	98.0%
Diesel Oil	0.0	3,448.4	3,448.4	0.0%
Natural Gas	0.0	78,255.3	78,255.3	0.0%
Other	325.0	1,850.0	2,175.0	14.9%
Total	38,976.9	84,322.7	123,299.6	31.6%

Table 8-29 shows NO_X emission controls by fossil fuel fired units in PJM. Coal has the highest NO_X emission rate, while natural gas and diesel oil have lower NO_X emission rates. Of the current 39,420.9 MW of coal capacity in PJM, 39,291.9 MW of capacity, 99.7 percent, has some form of emissions controls to reduce NO_X emissions. Most units in PJM have NO_X emission controls in order to meet each state's emission compliance standards, based on whether a state is part of CSAPR, Acid Rain Program (ARP) or a combination of the three. The NO_X compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[295]

290 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 4, 2022).
291 Air Markets Programs Data is submitted quarterly. Generators have 30 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year. The most recent complete set of emissions data is from 2024.
292 The total MW are less than the 181,290.0 reported in Section 5: Capacity Market, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed January 1, 2025).
293 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA, "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A, Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed May 7, 2020).
294 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.
295 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).

Table 8-29 NO_X emission controls by fuel type (MW): As of September 30, 2025

	NO_X Controlled	No NO_X Controls	Total	Percent Controlled
Coal	39,291.9	129.0	39,420.9	99.7%
Diesel Oil	1,020.3	2,428.1	3,448.4	29.6%
Natural Gas	77,288.3	967.0	78,255.3	98.8%
Other	775.0	1,400.0	2,175.0	35.6%
Total	118,375.5	4,924.1	123,299.6	96.0%

Table 8-30 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.8 percent) in PJM have particulate controls, as well as a few natural gas units (2.3 percent) and units with other fuel sources (53.9 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[296] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 39,420.9 MW of coal capacity in PJM, 39,335.9 MW of capacity, 99.8 percent, have some type of particulate emissions control technology.

Table 8-30 Particulate emission controls by fuel type (MW): As of September 30, 2025

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	39,335.9	85.0	39,420.9	99.8%
Diesel Oil	0.0	3,448.4	3,448.4	0.0%
Natural Gas	1,765.0	76,490.3	78,255.3	2.3%
Other	1,172.0	1,003.0	2,175.0	53.9%
Total	42,272.9	81,026.7	123,299.6	34.3%

In order to achieve compliance with MATS, most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR. Currently, all of the 97 coal steam units have some combination of ESP, baghouse, or FGD and SCR technology installed to achieve MATS compliance for either SO_2 or particulate emissions control, representing all of the 39,420.9 MW total coal capacity.

296 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed May 4, 2022).

Emissions

Figure 8-10 shows the total CO_2 emissions in short tons, the CO_2 emission rate in short tons per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the third quarter of 2025, and the CO_2 emission rate in short tons per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the third quarter of 2025.[297]

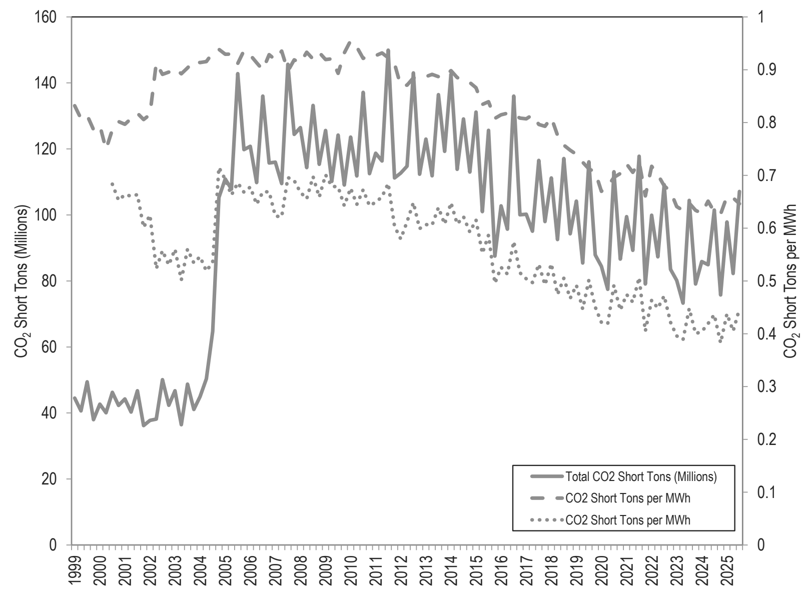
Figure 8-11 shows the total CO_2 emission in short tons on peak and off peak and the CO_2 emission rate in short tons per MWh for all CO_2 emitting units.

Table 8-31 shows the minimum and maximum CO_2 emission rates in short tons per MWh for all CO_2 emitting units, for all hours, as well as on and off peak hours, from the first quarter of 1999 through the third quarter of 2025.

Total PJM generation increased from 232,705.5 GWh in the third quarter of 2024 to 239,493.5 GWh in the third quarter of 2025, while CO_2 produced increased from 101.5 million short tons in the third quarter of 2024 to 107.1 million short tons in the third quarter of 2025.[298] The CO_2 emission rate averaged 0.64 short tons per MWh for all CO_2 emitting units in 2023, and 0.63 short tons per MWh for all CO_2 emitting units in 2024.

297 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
298 See the *2024 Annual State of the Market Report for PJM: Volume 2*, Section 3: Energy Market, Table 3-51.

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: January 1999 through September 2025[299 300]



In the third quarter of 2025, CO_2 emission rates were 0.64 short tons per MWh for all CO_2 emitting units for off peak hours, and 0.65 short tons per MWh for on peak hours. Of the top 10 largest CO_2 emitting units in the United States, three (Gavin, Prairie State, and Amos) are located in the PJM footprint.[301]

299 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
300 In 2004 and 2005, PJM integrated the American Electric Power (AEP), ComEd, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).
301 "The top 10 emitting power plants in America," <https://www.eenews.net/articles/the-top-10-emitting-power-plants-in-america/> (Accessed November 4, 2022).

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: January 1999 through September 2025[302]

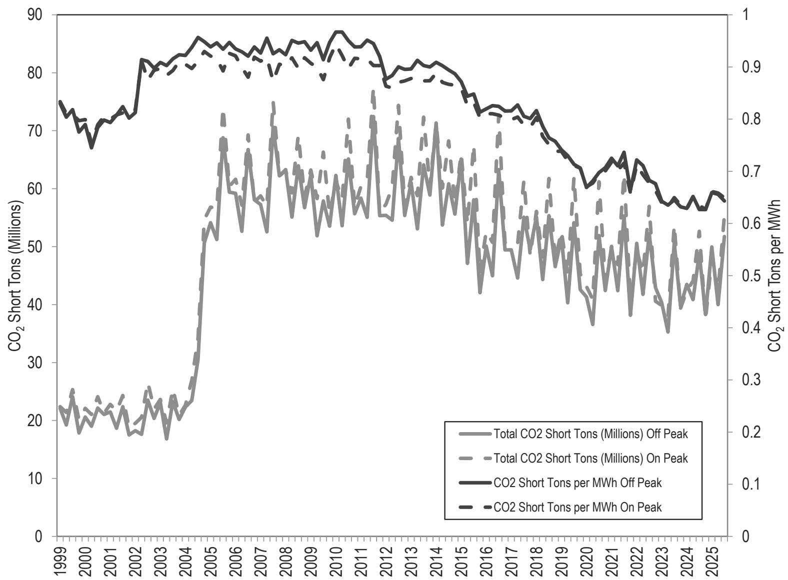


Table 8-31 Minimum and maximum CO_2 emissions per MWh: January 1999 through September 2025

		Short Tons per MWh	Year	Quarter
Minimum	All hours	0.63	2024	4
	On Peak	0.63	2024	4
	Off Peak	0.63	2024	4
Maximum	All hours	0.96	2010	1
	On Peak	0.94	2010	1
	Off Peak	0.97	2010	2

Figure 8-12 shows the total SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emission rate in short tons per MWh of total PJM generation. In the third quarter of 2025, the SO_2 emission rate was 0.000292 short tons per MWh for all SO_2 emitting units, and the NOx emission rate was 0.000198 short tons per MWh for all NO_X emitting units.

Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units. In the third quarter of 2025, SO_2 emission rates were 0.000287 short tons per MWh and 0.000297 short tons per MWh for all SO_2 units, for off and on peak hours. In the third quarter of 2025, NO_X emission rates were 0.000186 short tons per MWh and 0.000209 short tons per MWh for all NO_X emitting units, for off and on peak hours.

Table 8-32 shows the minimum and maximum SO2 and NOx emission rate in short tons per MWh for all SO_2 and NO_X emitting units, for all hours, as well as on and off peak hours, from the first quarter of 1999 through the third quarter of 2025.

The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2025.[303] [304]

302 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

303 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry,"<https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).

304 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

Figure 8-12 SO_2 and NO_x emissions by quarter (thousands of short tons), by PJM units: January 1999 through September 2025[305]

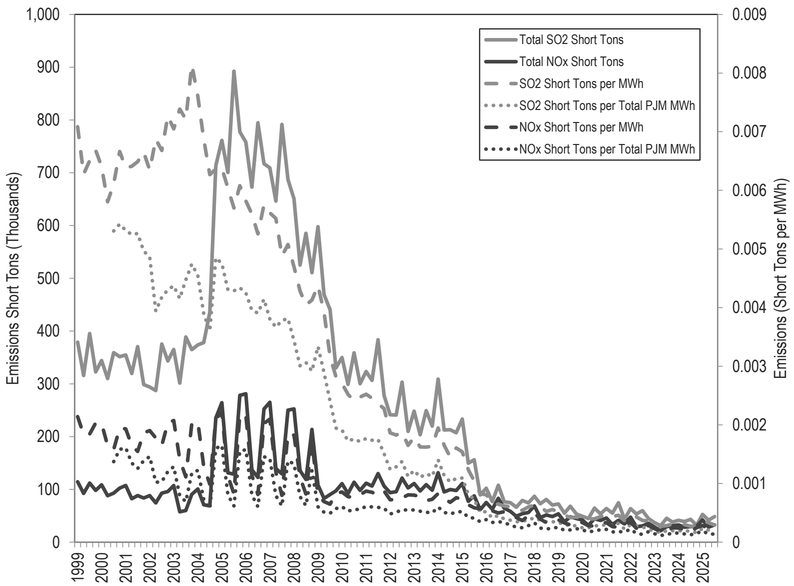


Figure 8-13 SO_2 and NO_x emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: January 1999 through September 2025[306]

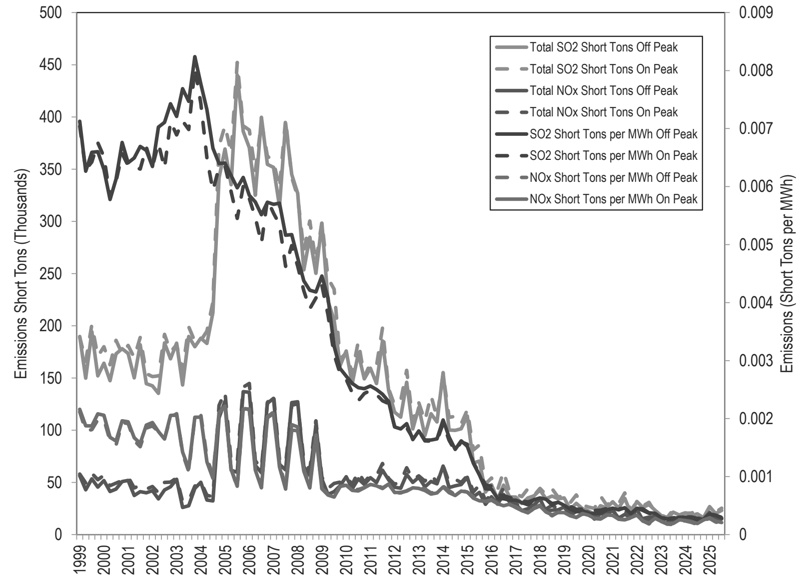


Table 8-32 Minimum and maximum SO_2 and NO_x emissions per MWh: January 1999 through September 2025

Emission Type			Short Tons per MWh	Year	Quarter
SO_2	Minimum	All hours	0.000	2024	4
		On Peak	0.000	2024	4
		Off Peak	0.000	2024	3
	Maximum	All hours	0.008	2003	4
		On Peak	0.008	2003	4
		Off Peak	0.008	2003	4
NO_x	Minimum	All hours	0.000	2023	3
		On Peak	0.000	2023	2
		Off Peak	0.000	2023	3
	Maximum	All hours	0.002	2005	1
		On Peak	0.002	2005	1
		Off Peak	0.002	2005	1

305 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

306 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Renewable Energy Output

Wind and Solar Peak Hour Output

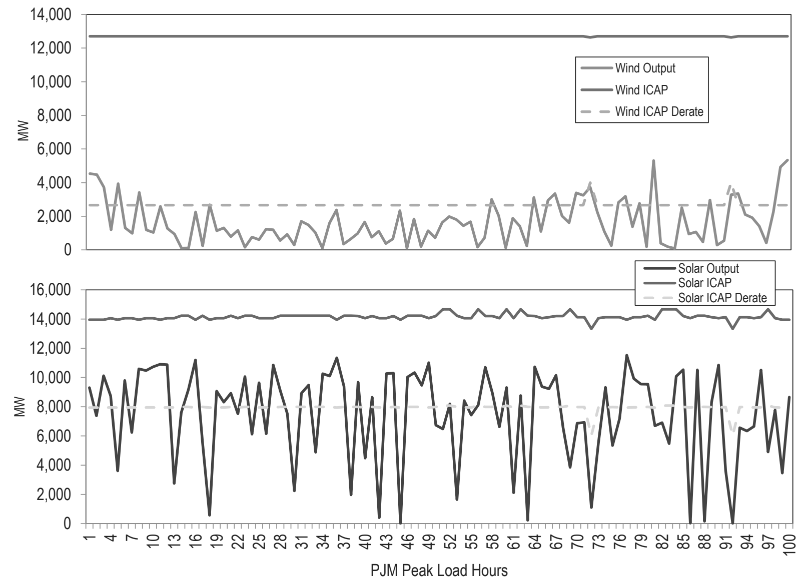
The capacity of solar and wind resources are derated from the nameplate or installed capacity value based on expected performance during hours with high risk of loss of load (unserved energy). Until June 1, 2023, PJM used average unit performance over 360 summer peak hours to determine the derating factors. For the 2023/2024 Delivery Year, which began on June 1, 2023, PJM used an average ELCC approach to determine the capacity derating factor.[307] The average ELCC approach was also used for the 2024/2025 Delivery Year. Beginning with the 2025/2026 Delivery Year, PJM changed to a marginal ELCC approach.[308] [309]

To illustrate the relationship between actual output and derating factors, Figure 8-14 shows wind and solar output during the top 100 load hours in PJM in the first nine months of 2025. Figure 8-15 shows wind and solar output for all hours in the first nine months of 2025. In the first nine months of 2025, 97 of the top 100 load hours in PJM are PJM defined peak load hours. The hours in Figure 8-14 are in descending order by load and the hours in Figure 8-15 are in chronological order. The solid lines represent the total ICAP and output of the wind or solar PJM resources. The dashed lines are the total capacity committed for each capacity resource, or the ICAP of wind and solar PJM resources derated by the applicable ELCC class rating if the unit is not a capacity resource.

The actual output of the wind and solar resources during the top 100 load hours varied both above and below the derated capacity values. Wind output was above the derated ICAP for 20 hours and below the derated ICAP for 80 hours of the top 100 load hours in the first nine months of 2025. The wind capacity factor for the top 100 load hours in the first nine months of 2025 was 12.9 percent. Wind output was above the derated ICAP for 2,921 hours and below the derated ICAP for 3,630 hours in the first nine months of 2025. The wind capacity factor in the first nine months of 2025 was 26.7 percent.

Solar output was above the derated ICAP for 55 hours and below the derated ICAP for 45 hours of the top 100 load hours in the first nine months of 2025. The solar capacity factor for the top 100 load hours in the first nine months of 2025 was 52.7 percent. Solar output was above the derated ICAP for 1,459 hours and below the derated ICAP for 5,092 hours in the first nine months of 2025. The solar capacity factor in the first nine months of 2025 was 22.5 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: January through September, 2025



307 See Capacity Value of Intermittent Resources (ELCC) in *2024 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market.
308 *Protest of the Independent Market Monitor for PJM*, ER24-99-000 (November 9, 2023).
309 Order 186 FERC ¶ 61,080 accepting PJM's marginal ELCC approach (January 30, 2024).

Figure 8-15 Wind and solar output: January through September, 2025

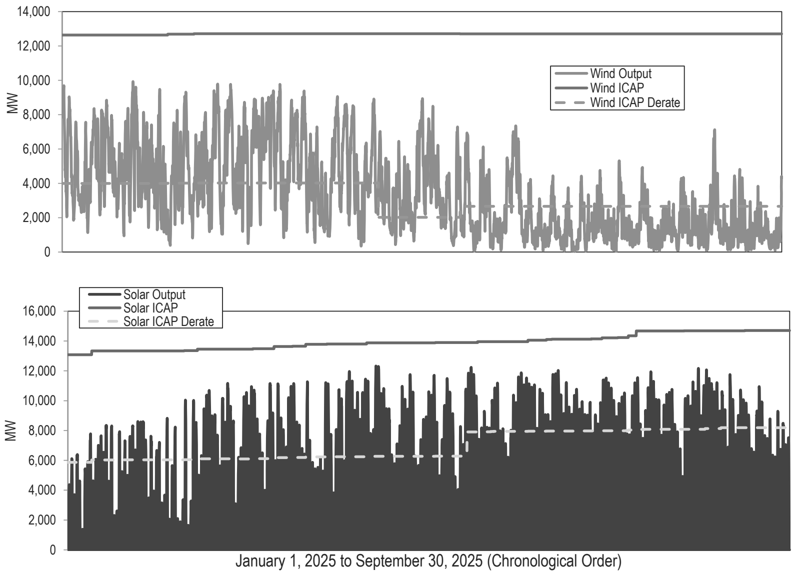


Figure 8-15 includes the impacts of the ELCC rules and winter CIR rules on the derated capacity values. The derated capacity for wind units reflects winter CIRs. On May 1, the CIRs for wind generators reverted from the winter ratings to the normal summer ratings which is reflected in Figure 8-15 as a step down of the wind ICAP derate line on May 1. On June 1, the ELCC ratings changed for the 2025/2026 capacity market delivery year.[310] This change is reflected in Figure 8-15 as a step up of the wind and solar ICAP derate lines on June 1. The increases in the solar ICAP line and the wind ICAP line reflect new generators coming online.

Wind Units

Table 8-33 shows the capacity factors of wind units in PJM. In the first nine months of 2025, the capacity factor of wind units in PJM was 26.7 percent. Wind units that were capacity resources had a capacity factor of 26.9 percent and an installed capacity of 11,862.8 MW. Wind units that were energy only had a capacity factor of 24.1 percent and an installed capacity of 832.7 MW. Wind capacity resources were derated to 14.7 or 17.6 percent of installed capacity for the capacity market prior to June 1, 2023, based on the wind farm terrain. Beginning June 1, 2023, wind capacity is derated to the ELCC accredited UCAP value.[311]

Table 8-33 Capacity factor of wind units: January through September, 2025

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	24.1%	832.7
Capacity Resource	26.9%	11,862.8
All Units	26.7%	12,695.5

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly real-time generation and day-ahead commitment of wind units in PJM, by month and hour of the day for the first nine months of 2025. The hour with the highest average output in the first nine months of 2025 was hour 1 in March with an average of 6,010.6 MWh. The hour with the lowest average output in the first nine months of 2025 was hour 11 in June with an average of 771.4 MWh. Wind output in PJM is generally higher during off peak hours and lower during on peak hours. Wind output is generally highest during the months from November through March and lowest during the months from May through September.

Wind resources' day-ahead commitments are lower than real-time generation for most hours. Table 8-34 provides a summary of the deviations between wind resources' real-time generation and day-ahead commitments. In January 2025, hourly real-time generation exceeded day-ahead commitments by 1,572.6 MWh on average, the highest average monthly deviation for the first nine months of 2025. The lowest monthly average deviation occurred in July with hourly real-time generation exceeding day-ahead commitments by 332.7 MWh on average. Wind generation exceeded day-ahead commitments in 81.6 percent of hours in the first nine months of 2025. July had the highest

310 *ELCC Class Ratings for 2024-2025*, PJM Interconnection, L.L.C. (December 29, 2023) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

311 ELCC rates and data are available on the PJM website <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

number of hours, 34.9 percent, with day-ahead commitments exceeding real time generation.

Figure 8-16 Average hourly real-time generation and day-ahead commitments of wind units: January through September, 2025

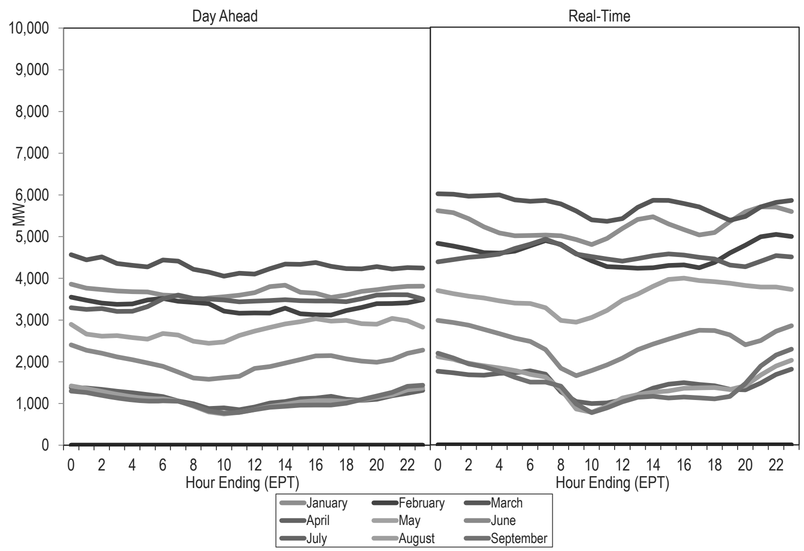


Table 8-34 Deviations between real-time wind generation and day-ahead commitments by month:[312] January through September, 2025

Month	Average Hourly Deviation	Minimum Hourly Deviation	Maximum Hourly Deviation	Hours with Negative Deviation
January	1,572.6	(1,957.7)	3,726.6	5.1%
February	1,251.2	(2,511.6)	3,900.0	9.8%
March	1,440.0	(799.6)	3,793.7	6.3%
April	1,078.5	(1,083.8)	3,684.1	16.0%
May	804.7	(1,171.5)	3,233.2	12.5%
June	476.4	(2,195.8)	3,048.9	31.0%
July	332.7	(1,060.2)	2,863.9	34.9%
August	416.3	(684.5)	2,115.7	22.6%
September	409.8	(893.7)	2,722.1	26.8%

312 Hourly deviations are equal to the real-time generation less day-ahead commitments.

Table 8-35 shows the generation and capacity factor of wind units by month for the first nine months in 2024 and 2025.

Table 8-35 Capacity factor of wind units in PJM by month: January through September, 2024 and 2025

	2024		2025	
Month	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
January	3,127.6	33.7%	3,907.9	41.6%
February	2,975.8	34.2%	3,084.0	36.2%
March	3,890.8	42.0%	4,261.9	45.1%
April	3,569.2	39.7%	3,259.4	35.6%
May	2,136.4	23.0%	2,660.4	28.1%
June	2,233.4	24.9%	1,780.2	19.5%
July	1,151.4	12.4%	1,090.0	11.5%
August	1,233.6	13.3%	1,123.5	11.9%
September	1,496.1	16.7%	1,062.3	11.6%
October	2,670.4	28.8%		
November	3,410.5	37.8%		
December	3,496.7	37.2%		

Output from wind turbines displaces output from other generation types because, in general, wind turbines generate power when the wind is blowing, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output.[313] Figure 8-17 and Table 8-36 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first nine months of 2025. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In the first nine months of 2025, the SCED dispatch instruction for marginal wind resources was to reduce output for 67.5 percent of the marginal wind unit intervals. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated by this metric.

313 The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

Figure 8-17 Marginal fuel at time of wind generation: January through September, 2025

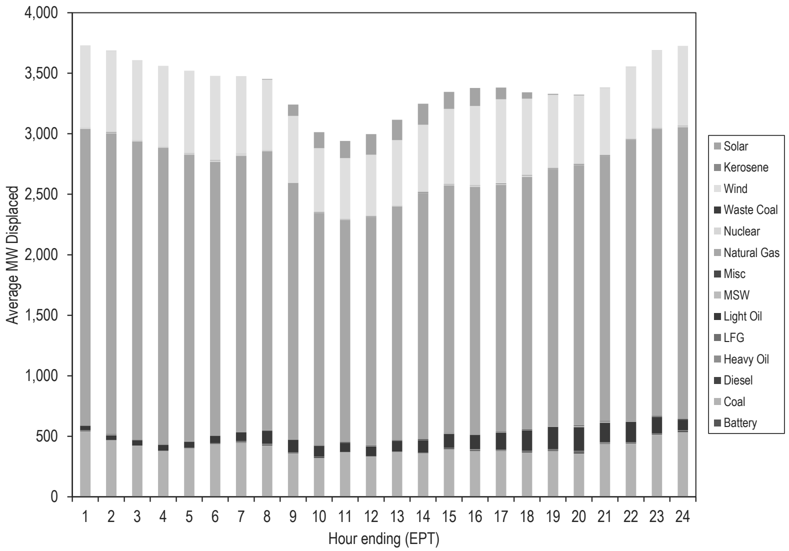


Table 8-36 Marginal fuel MW at time of wind generation: January through September, 2025

Hour	Battery	Coal	Diesel	Heavy Oil	LFG	Light Oil	MSW	Misc	Natural Gas	Nuclear	Waste Coal	Wind	Kerosene	Solar	Total
0	2.6	539.2	2.6	0.7	5.9	34.6	1.0	1.4	2,452.7	7.8	0.7	681.4	0.0	0.0	3,730.6
1	3.1	463.3	0.0	1.5	2.3	39.0	4.3	4.3	2,484.9	7.0	3.4	672.1	0.8	0.0	3,686.1
2	0.8	421.9	0.0	0.6	0.9	44.8	0.7	2.7	2,464.2	8.6	1.5	662.3	0.0	0.0	3,609.1
3	0.0	379.5	0.0	0.5	1.5	48.8	2.8	2.6	2,449.4	9.7	0.0	666.2	0.0	0.0	3,560.9
4	1.7	400.5	1.5	1.0	0.8	50.4	1.2	0.6	2,369.8	11.6	1.2	680.5	0.0	0.0	3,521.0
5	0.0	436.0	3.3	1.3	4.5	59.2	1.4	0.1	2,260.8	13.1	1.6	697.7	0.0	0.0	3,478.9
6	0.0	444.0	3.3	2.6	11.7	73.0	4.4	1.6	2,277.3	18.9	1.3	634.6	0.5	0.0	3,473.2
7	0.6	422.9	7.3	1.6	6.4	108.2	3.6	2.7	2,302.9	6.3	1.1	584.0	0.4	5.7	3,447.9
8	0.0	359.7	3.7	0.5	2.8	105.0	1.7	0.3	2,120.0	2.4	0.0	550.8	1.2	92.6	3,148.3
9	0.0	321.1	9.0	0.9	1.8	90.2	2.3	1.8	1,918.2	5.9	1.7	528.9	0.4	131.1	2,882.3
10	0.0	369.7	0.6	0.0	0.2	75.4	0.8	6.7	1,834.9	5.8	1.9	502.4	0.0	141.6	2,798.4
11	0.0	334.5	0.0	0.0	0.9	81.9	2.5	4.6	1,890.2	2.6	1.9	507.6	0.0	169.6	2,826.7
12	0.0	369.4	1.8	1.5	1.2	89.8	2.3	5.3	1,929.4	3.6	0.4	542.6	0.0	168.4	2,947.2
13	0.8	359.6	3.7	0.6	0.5	101.9	2.1	7.0	2,035.3	3.6	3.8	555.8	0.0	173.8	3,074.6
14	0.0	394.2	7.4	0.5	5.1	113.6	4.6	2.3	2,045.4	8.2	2.5	622.0	0.0	140.2	3,205.7
15	0.0	379.3	6.6	2.9	5.1	118.2	5.0	2.5	2,041.5	10.7	2.9	655.3	0.0	147.9	3,230.0
16	1.2	379.3	3.0	3.0	2.4	142.1	5.4	3.4	2,037.4	7.6	2.8	696.8	0.0	97.1	3,284.5
17	1.0	364.9	7.2	0.5	8.3	167.7	2.2	4.1	2,087.4	12.4	2.4	631.2	0.0	53.7	3,289.3
18	0.0	378.3	6.7	1.1	7.8	183.1	3.0	1.5	2,129.9	3.9	1.2	604.5	0.8	8.0	3,321.8
19	0.0	358.3	7.8	1.4	12.4	195.9	9.2	6.0	2,149.8	4.9	3.7	566.8	1.8	4.7	3,318.1
20	0.0	437.7	4.5	3.2	5.7	161.7	10.1	3.5	2,192.7	3.3	2.1	554.4	0.5	1.6	3,379.4
21	0.0	441.0	5.9	0.9	4.6	167.8	9.1	1.5	2,321.6	3.5	1.5	596.4	0.6	0.0	3,554.3
22	0.0	515.2	3.6	1.2	3.8	135.5	4.2	4.2	2,373.2	6.1	1.0	639.8	1.1	0.0	3,688.8
23	0.0	534.7	8.6	2.2	3.3	86.4	0.5	9.5	2,408.8	9.7	2.1	660.3	0.0	0.0	3,726.2
Average	0.5	408.5	4.1	1.3	4.2	103.1	3.5	3.3	2,190.7	7.4	1.8	612.3	0.3	55.7	3,341.0

Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all and only PJM solar units that are in front of the meter. As shown in Table 8-22, there are 15,526.7 MW of solar capacity registered in GATS that are PJM units. As shown in Table 8-23, there are 14,180.5 MW capacity of solar registered in GATS that are not PJM units. Some behind the meter generation exists in clusters, such as community solar farms. The customers of these clusters may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to avoid paying appropriate costs as a result of badly designed rules, such as rules for netting. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-37 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 22.5 percent for the first nine months of 2025. Solar units that were capacity resources had a capacity factor of 22.8 percent and an installed capacity of 13,515.3 MW. Solar units that were energy only had a capacity factor of 12.2 percent and an installed capacity of 416.4 MW. Solar capacity resources were derated to 38.0, 42.0 or 60.0 percent of installed capacity for the capacity market, prior to June 1, 2023, based on the installation type. Beginning June 1, 2023, solar capacity is derated to the ELCC accredited UCAP value.

Table 8-37 Capacity factor of solar units: January through September, 2025

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	12.2%	416.4
Capacity Resource	22.8%	13,515.3
All Units	22.5%	13,931.7

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-18 shows the average real-time generation and day-ahead commitments of solar units in PJM, by month and hour of day.[314] The hour with the highest average output in the first nine months of 2025, was hour 13 in July with an average of 9,720.7 MW. January has the lowest solar output. The hour in January with the highest average output was hour 13 with an average of 5,847.4 MW. Solar output in PJM is generally higher during peak hours and lower during off peak hours. Solar output is generally highest during the months from May through August and lowest during the months from November through February.

Solar unit day-ahead commitments are lower than real-time generation for most hours. Table 8-38 provides a summary of the deviations between solar unit real-time generation and day-ahead commitments. In April 2025, hourly real-time solar unit generation exceeded day-ahead solar unit commitments by 636.6 MWh on average, the highest average monthly deviation. The lowest monthly average deviation occurred in September with hourly real-time solar unit generation exceeding day-ahead commitments by 209.8 MWh on average. Solar generation exceeded day-ahead commitments in 72.3 percent of hours in the first nine months of 2025. June had the highest number of hours, 42.4 percent, with day-ahead commitments exceeding real-time generation.

Figure 8-18 Average hourly real-time generation and day-ahead commitments of solar units: January through September, 2025

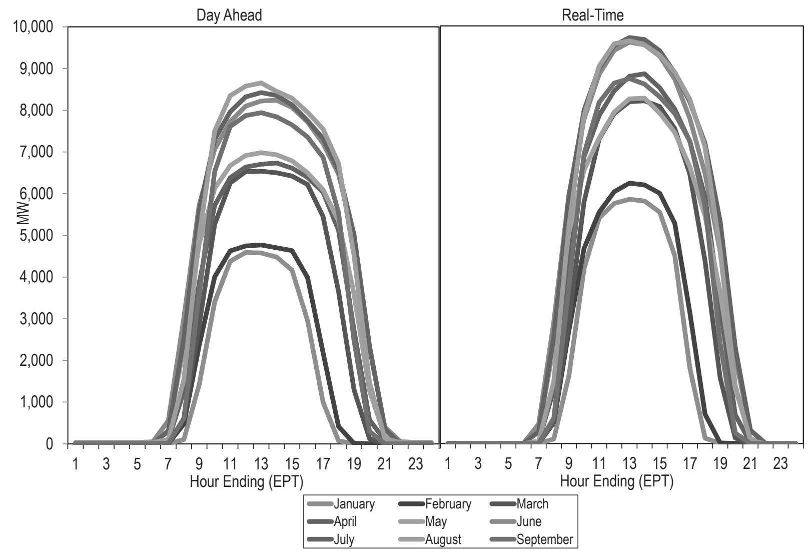


Table 8-38 Deviations between real-time solar generation and day-ahead commitments by month:[315] January through September, 2025

Month	Average Hourly Deviation	Minimum Hourly Deviation	Maximum Hourly Deviation	Hours with Negative Deviation
January	394.1	(1,507.9)	3,519.7	33.7%
February	428.1	(893.6)	4,028.3	18.3%
March	470.2	(1,571.7)	3,898.2	21.0%
April	636.6	(1,441.6)	5,237.1	23.8%
May	319.5	(2,424.0)	3,111.4	28.0%
June	319.2	(2,160.4)	2,789.2	42.4%
July	415.7	(1,909.4)	2,780.8	22.8%
August	286.7	(2,108.4)	2,943.5	35.2%
September	209.8	(1,416.3)	2,285.2	23.6%

314 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.

315 Hourly deviations are equal to the real-time generation less day-ahead commitments.

Table 8-39 shows the generation and capacity factor of solar units by month for the first nine months of 2024 and 2025.

Table 8-39 Capacity factor of solar units by month: January through September, 2024 and 2025

	2024		2025	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	573,863.5	8.0%	1,261,428.3	12.8%
February	1,024,321.1	15.1%	1,315,560.8	14.6%
March	1,264,115.0	17.1%	2,136,371.8	21.2%
April	1,490,595.4	20.2%	2,407,611.9	24.2%
May	1,716,141.0	22.0%	2,433,709.0	23.6%
June	2,166,385.1	28.0%	2,811,979.3	27.9%
July	2,050,807.0	25.6%	2,983,606.2	28.3%
August	1,993,138.9	24.1%	2,851,763.9	26.2%
September	1,526,641.4	18.6%	2,316,936.4	21.9%
October	1,759,610.5	19.7%		
November	1,028,502.6	11.5%		
December	905,724.9	9.6%		

Output from solar generators displaces output from other generation types because, in general, solar photovoltaic cells generate power when the sun is shining, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of solar photovoltaic cell output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when a solar unit is producing output.[316] Figure 8-19 and Table 8-40 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time solar generation in the first nine months of 2025. This is not an exact measure of displacement because it is not based on a redispatch of the system without solar resources. In the first nine months of 2025, the SCED dispatch instruction for marginal solar resources was to reduce output for 97.6 percent of the marginal solar unit intervals. When solar appears as the displaced fuel at times when solar resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of solar displaced by solar is thus overstated by this metric.

316 The measure is based on the principle that any incremental change in the solar output is balanced by the change in the output of marginal generators, while holding everything else equal.

Figure 8-19 Marginal fuel at time of solar generation: January through September, 2025

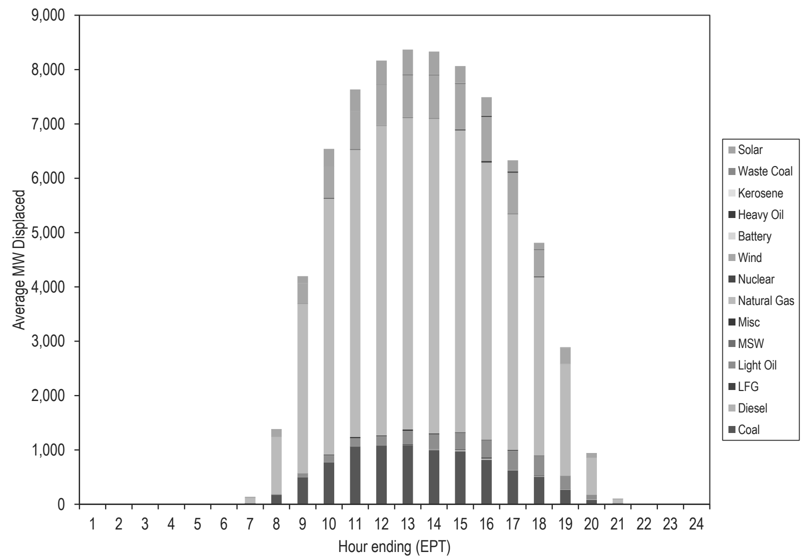


Table 8-40 Marginal fuel MW at time of solar generation: January through September, 2025

Hour	Coal	Diesel	LFG	Light Oil	MSW	Misc	Natural Gas	Nuclear	Wind	Battery	Heavy Oil	Kerosene	Waste Coal	Solar	Total
0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
3	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
4	0.1	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.5
5	0.2	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.2	0.0	0.0	0.0	0.0	0.0	1.7
6	18.5	0.0	0.0	0.2	0.1	0.2	101.5	0.5	12.6	0.0	0.0	0.0	0.0	0.0	133.5
7	172.4	0.3	0.6	9.4	0.7	0.3	1,060.1	2.8	128.9	0.3	0.1	0.0	0.0	4.7	1,380.7
8	498.2	2.4	3.0	63.1	0.8	1.5	3,117.7	5.9	374.1	0.0	0.6	0.4	0.0	130.0	4,197.7
9	774.3	6.5	4.8	109.9	11.0	9.2	4,709.2	11.2	572.8	0.0	2.0	0.3	7.1	322.7	6,541.0
10	1,062.1	0.8	1.3	147.8	2.5	25.3	5,283.6	12.6	693.2	0.0	0.0	0.0	2.2	403.1	7,634.4
11	1,080.1	0.0	4.2	161.9	9.2	12.9	5,697.0	8.1	745.8	0.0	1.8	0.0	4.4	441.0	8,166.3
12	1,087.2	4.2	14.4	237.8	5.7	27.5	5,733.8	10.6	774.7	0.0	11.0	0.0	3.1	457.2	8,367.3
13	998.6	14.5	6.1	259.2	9.2	19.2	5,787.9	10.5	787.4	1.0	6.4	0.0	12.5	419.2	8,331.9
14	972.3	24.5	12.0	297.2	7.2	12.3	5,555.4	16.5	841.3	0.0	10.8	0.0	7.9	308.0	8,065.5
15	818.0	24.2	16.7	313.9	11.4	5.4	5,097.7	31.4	810.5	0.0	17.0	0.0	10.3	335.3	7,491.9
16	625.5	6.1	6.4	342.0	8.0	13.8	4,337.5	10.2	749.4	2.5	22.2	0.0	6.0	201.1	6,330.6
17	508.7	10.2	9.2	359.4	9.2	6.1	3,274.5	18.5	486.5	1.3	7.9	0.0	5.7	114.8	4,812.0
18	268.9	9.7	9.7	231.9	2.5	3.0	2,054.3	2.7	287.5	0.0	2.5	0.0	5.6	12.3	2,890.8
19	82.0	4.8	3.0	80.4	2.8	3.6	677.1	0.8	83.9	0.0	1.9	0.0	0.7	3.0	944.0
20	10.7	1.0	0.1	7.4	0.4	0.2	70.3	0.1	7.3	0.0	0.0	0.0	0.0	0.1	97.7
21	0.1	0.1	0.0	0.1	0.0	0.0	0.9	0.0	0.1	0.0	0.0	0.0	0.0	0.0	1.2
22	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
23	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Average	374.1	4.6	3.8	109.2	3.4	5.9	2,190.0	5.9	306.5	0.2	3.5	0.0	2.7	131.4	3,141.2

Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2025, PJM was a monthly net exporter of energy in the real-time energy market in all months.[1] In the first nine months of 2025, the real-time net interchange was -29,800.7 GWh. The real-time net interchange in the first nine months of 2024 was -27,542.0 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first nine months of 2025, the total day-ahead net interchange was -26,230.6 GWh. The day-ahead net interchange in the first nine months of 2024 was -24,393.4 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2025, gross imports in the day-ahead energy market were 62.0 percent of gross imports in the real-time energy market (75.3 percent in the first nine months of 2024). In the first nine months of 2025, gross exports in the day-ahead energy market were 80.4 percent of the gross exports in the real-time energy market (84.8 percent in the first nine months of 2024).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2025, there were net scheduled exports at 14 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2025, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions in the real-time energy market.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, there were net scheduled exports at 15 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, up to congestion transactions were net exports at three of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Inadvertent Interchange.** In the first nine months of 2025, net scheduled interchange was -29,800.7 GWh and net actual interchange was -29,592.4 GWh, a difference of 208.4 GWh. In the first nine months of 2024, the difference was 196.4 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first nine months of 2025, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -799.7 GWh of net scheduled interchange and -8,409.3 GWh of net actual interchange, a difference of 7,609.6 GWh. In the first nine months of 2025, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 2,746.0 GWh of net scheduled interchange and 6,535.3 GWh of net actual interchange, a difference of 3,789.3 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2025, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 52.4 percent of the hours.

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

- **PJM and New York ISO Interface Prices.** In the first nine months of 2025, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 59.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 81.5 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 80.3 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2025, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 80.7 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in the first nine months of 2025, and zero such TLRs in the first nine months of 2024.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 57.7 percent, from 36,083 bids per day in the first nine months of 2024 to 48,979 bids per day in the first nine months of 2025. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 10.1 percent, from 237,417 MWh per day in the first nine months of 2024, to 264,091 MWh per day in the first nine months of 2025.

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)

- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends eliminating the mechanism that defines FFE and M2M payments. These mechanisms are not consistent with markets and are not needed for efficient interface pricing. The MMU recommends that PJM file with the Commission to eliminate the FFE calculation and M2M payment of the PJM and MISO joint operating agreement. (Priority: Medium. First reported 2024. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends clear rules governing when PJM may recall capacity backed exports. (Priority: Medium. First reported 2010. Status: Partially adopted.)

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features of an energy market including locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features. Pricing in the market areas is transparent and pricing in the nonmarket areas is not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market across the interfaces.

It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. External entities wishing to receive the benefits of the PJM LMP market should join PJM.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. Following the termination of the Northwest pricing point on October 1, 2020, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The MMU continues to recommend the termination of the Ontario interface pricing point. The Ontario interface pricing point is noncontiguous to the PJM footprint that creates opportunities for market participants to engage in sham scheduling activities.

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the real-time or day-ahead energy market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.[2]

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		X
Balancing Operating Reserve	X	X	X						X
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

[1] No charge if Point of Delivery is MISO
[2] No charge for spot in transmission

2 For an explanation and current rate for each billing line item, see "*Quick Reference Guide to Market Settlements By Type of Business*" (February 1, 2023) <https://www.pjm.com/-/media/DotCom/training/core-curriculum/ip-ms-301/ms-301-quick-reference-guide-to-markets-settlements-by-type-of-business.pdf>.

Aggregate Imports and Exports

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for the first nine months of 2024 and 2025. In the first nine months of 2025, gross imports in the day-ahead energy market were 62.0 percent of gross imports in the real-time energy market (75.3 percent in the first nine months of 2024). In the first nine months of 2025, gross exports in the day-ahead energy market were 80.4 percent of gross exports in the real-time energy market (84.8 percent in the first nine months of 2024).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through September, 2024 and 2025

Category	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change
Real-Time Gross Imports	10,781.6	12,328.6	14.3%
Real-Time Gross Exports	38,323.6	42,129.3	9.9%
Real-Time Net Interchange	(27,542.0)	(29,800.7)	8.2%
Day-Ahead Gross Imports	8,115.1	7,646.1	(5.8%)
Day-Ahead Gross Exports	32,508.5	33,876.7	4.2%
Day-Ahead Net Interchange	(24,393.4)	(26,230.6)	7.5%
Monthly Average Real-Time Gross Exports	4,258.2	4,681.0	9.9%
Monthly Average Real-Time Gross Imports	1,198.0	1,369.8	14.3%
Monthly Average Day-Ahead Gross Exports	3,612.1	3,764.1	4.2%
Monthly Average Day-Ahead Gross Imports	901.7	849.6	(5.8%)

In the first nine months of 2025, PJM was a monthly net exporter of energy in the real-time energy market in all months. In the first nine months of 2025, PJM was a monthly net exporter of energy in the day-ahead energy market in all months (Figure 9-1).[3]

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

Transactions in the day-ahead energy market create financial obligations to deliver in the real-time energy market and to pay operating reserve charges based on differences between the transaction MWh in the day-ahead and real-time energy markets times the applicable operating reserve rates. Up to congestion transactions also create financial obligations to deliver in real time, but did not pay operating reserve charges until November 1, 2020.

Figure 9-1 Scheduled imports and exports: January through September, 2025

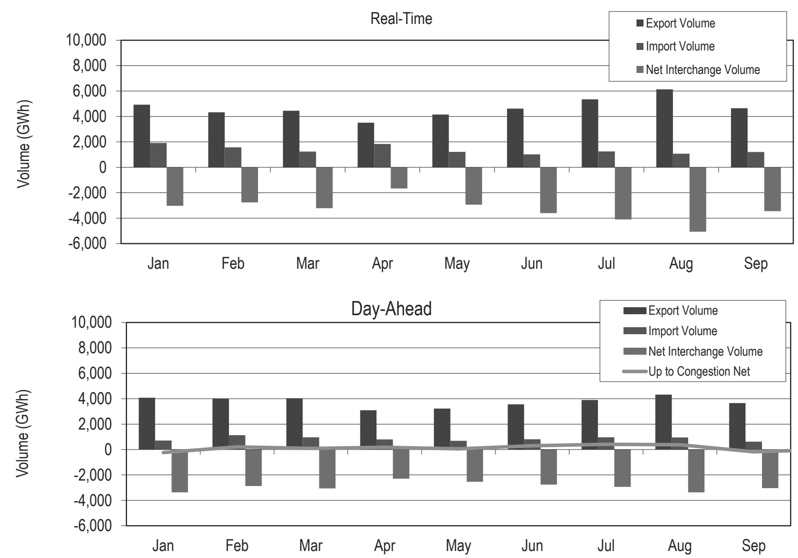


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through September 2025. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the real-time and day-ahead energy markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. The net direction of power flows is generally expected to be a function of price differences net of transactions costs. Since the modification of the up to congestion product in September 2010, up to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the day-ahead energy market. On

3 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

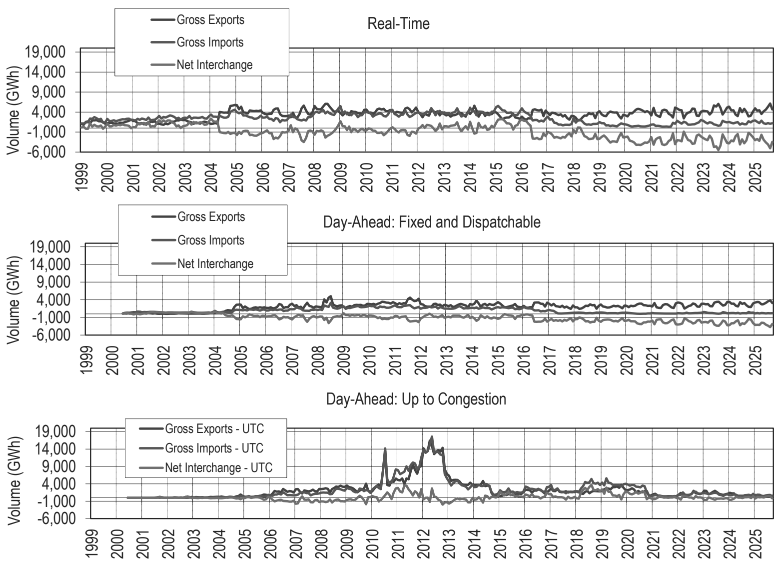
November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. While the gross import and export volumes in the day-ahead energy market decreased, PJM has remained primarily a net exporter in the day-ahead energy market. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a net exporter in the real-time and day-ahead energy markets. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[4] As a result, the volume of import and export up to congestion transactions increased, contributing to PJM becoming a net importer in the day-ahead energy market starting in March 2018. On July 16, 2020, FERC issued an order directing PJM to revise uplift allocation rules to allocate uplift to up to congestion transactions.[5] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. As a result, the volume of up to congestion transactions decreased, and PJM became a net exporter in the day-ahead energy market.

In February 2021, winter storms caused significant generation outages in Texas and resulted in power outages across the Electric Reliability Council of Texas (ERCOT) region. These outages occurred between February 10, 2021, and February 27, 2021. During this time, ERCOT imported generation from neighboring regions. While PJM did not have any scheduled exports directly to the ERCOT region, PJM exports during this time increased from an average hourly export of 4,772 MW per hour between February 1 and February 10, 2021, to 7,003 MW per hour between February 10 and February 27, 2021.

On June 13, 2022, PJM experienced several intervals of shortage pricing that resulted in high LMPs during the period from 1450 (EPT) through 1800 (EPT). PJM remained a net exporter of energy throughout the period despite the fact that PJM prices were much higher than MISO prices. PJM net exports averaged 4,431 MW during hours ending 1500 (EPT) through 1800 (EPT), a slight decrease from average net exports of 5,560 MW during the hours ending 1100 (EPT) through 1400 (EPT). Market participant response to the pricing signals in this period was affected by TLRs issued by MISO, SWPP and PJM, although the curtailments of scheduled imports to PJM were relatively small compared to the net exports. Export transactions to MISO continued to flow during this period primarily on firm and grandfathered transmission service. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first nine months of 2025, flows were in the uneconomic direction on the PJM/MISO interface in 47.6 percent of all hours.

4 162 FERC ¶ 61,139.
5 172 FERC ¶ 61,046.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through September 30, 2025



Real-Time Interface Imports and Exports

In the real-time energy market, scheduled imports and exports are defined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. Table 9-19 includes a list of active interfaces in the first nine months of 2025. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2025, PJM had 19 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. There are 10 separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-3 through Table 9-5 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the real-time energy market is shown by interface for the first nine months of 2025 in Table 9-3, while gross scheduled imports and exports are shown in Table 9-4 and Table 9-5.

In the real-time energy market, in the first nine months of 2025, there were net scheduled exports at 14 of PJM's 19 interfaces. The top three net exporting interfaces in the real-time energy market accounted for 55.4 percent of the total net scheduled exports: PJM/NYISO (NYIS) with 21.1 percent, PJM/Cinergy (CIN) with 20.2 percent and PJM/MidAmerican Energy Company (MEC) with 14.2 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 48.1 percent of the total net PJM scheduled exports in the real-time energy market. There were net scheduled exports in the real-time energy market at seven of the 10 separate interfaces that connect PJM to MISO. Those seven exporting interfaces represented 49.3 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first nine months of 2025, there were net scheduled imports at four of PJM's 19 interfaces. The top two importing interfaces in the real-time energy market accounted for 75.6 percent of the total net scheduled imports: PJM/Duke (DUK) with 42.3 percent and PJM/Ameren-Illinois (AMIL) with 33.4 percent of the total net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the real-time energy market. There were net scheduled imports in the real-time energy market at two of the 10 separate interfaces that connect PJM to MISO (Ameren-Illinois (AMIL) and Indianapolis Power & Light (IPL). These importing interfaces represented 38.1 percent of the total net PJM scheduled imports in the real-time energy market.[6]

6 In the real-time energy market, one PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP)). CWLP is a balancing authority on the western side of MISO.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(181.1)	(25.4)	(49.1)	47.3	33.7	(29.3)	(42.4)	21.3	9.7	(215.2)
CPLW	0.0	0.0	0.0	0.5	0.0	0.1	0.0	0.0	(0.8)	(0.1)
DUK	(132.8)	340.7	91.3	294.4	227.6	56.4	(5.2)	200.5	268.6	1,341.5
LGEE	(10.7)	(44.1)	(103.5)	(37.7)	(41.5)	(85.5)	(89.9)	(123.4)	(89.3)	(625.5)
MISO	(735.0)	(875.9)	(1,261.2)	(698.1)	(1,923.9)	(1,995.2)	(2,257.9)	(3,225.4)	(2,080.2)	(15,052.8)
ALTE	(123.6)	(143.9)	(154.2)	(42.5)	(207.1)	(238.2)	(330.7)	(448.1)	(156.5)	(1,844.8)
ALTW	(6.9)	(6.6)	(13.5)	10.0	(15.9)	(22.3)	(23.2)	(52.3)	(40.9)	(171.6)
AMIL	570.9	313.2	117.2	196.8	14.5	(43.5)	(30.7)	(55.0)	(24.7)	1,058.8
CIN	(789.3)	(574.9)	(600.0)	(145.3)	(619.1)	(749.9)	(1,092.3)	(1,331.6)	(751.2)	(6,653.6)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	60.7	5.5	57.0	78.1	(54.3)	18.8	18.6	(24.1)	(8.2)	152.0
MEC	(425.0)	(333.2)	(402.7)	(575.1)	(633.3)	(571.4)	(507.6)	(624.6)	(614.3)	(4,687.0)
MECS	156.7	(23.6)	(113.0)	55.7	(209.1)	(223.3)	(157.1)	(434.2)	(312.4)	(1,260.3)
NIPS	(72.7)	(45.6)	(74.8)	(278.0)	(103.8)	(64.6)	(48.5)	(59.6)	(52.2)	(799.7)
WEC	(105.7)	(66.8)	(77.2)	2.1	(95.9)	(100.8)	(86.4)	(196.0)	(119.7)	(846.5)
NYISO	(1,867.7)	(2,237.3)	(2,076.2)	(1,260.6)	(1,451.9)	(1,476.9)	(1,742.0)	(1,982.1)	(1,775.5)	(15,870.2)
HUDS	(173.6)	(275.1)	(342.4)	(258.9)	(178.4)	(368.7)	(456.8)	(438.3)	(410.0)	(2,902.2)
LIND	(210.9)	(209.6)	(221.1)	(148.8)	(210.8)	(206.6)	(229.0)	(227.7)	(203.3)	(1,867.7)
NEPT	(493.1)	(450.8)	(478.2)	(419.7)	(400.4)	(471.1)	(501.0)	(471.4)	(473.3)	(4,158.9)
NYIS	(990.1)	(1,301.9)	(1,034.6)	(433.2)	(662.3)	(430.5)	(555.1)	(844.7)	(688.9)	(6,941.4)
TVA	(97.2)	85.5	185.0	(11.5)	223.8	(71.7)	41.2	45.1	221.3	621.5
Total	(3,024.5)	(2,756.5)	(3,213.6)	(1,665.8)	(2,932.2)	(3,602.1)	(4,096.1)	(5,063.9)	(3,446.1)	(29,800.7)

Table 9-4 Real-time scheduled gross import volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	6.4	59.7	19.5	78.0	65.5	20.1	9.4	48.4	54.8	361.9
CPLW	0.0	0.0	0.0	0.5	0.0	0.1	0.0	0.0	0.1	0.8
DUK	184.5	403.1	256.8	376.5	318.3	180.2	243.4	315.4	349.4	2,627.6
LGEE	110.3	55.6	24.8	50.5	13.6	34.2	41.9	9.1	1.4	341.3
MISO	1,169.2	550.5	495.7	813.5	333.7	376.1	404.1	235.7	293.7	4,672.1
ALTE	15.4	7.1	13.3	36.9	10.3	32.6	21.5	11.0	6.3	154.4
ALTW	12.2	11.7	14.6	27.7	7.3	18.0	8.7	5.8	5.5	111.5
AMIL	574.1	325.4	127.7	225.0	122.2	28.0	10.6	7.5	11.7	1,432.1
CIN	131.5	40.5	76.3	159.8	42.7	88.1	113.8	82.6	128.1	863.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	63.0	19.1	80.0	96.4	50.2	59.4	49.4	32.1	46.4	495.9
MEC	62.0	53.0	56.0	47.4	40.4	29.6	36.2	29.6	20.0	374.1
MECS	265.4	72.9	94.8	164.0	40.4	110.7	127.6	58.6	63.1	997.5
NIPS	(0.7)	(0.7)	(0.8)	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	0.9	(5.1)
WEC	46.4	21.6	33.7	57.0	21.0	10.5	37.0	9.3	11.7	248.1
NYISO	146.7	112.6	145.9	110.3	119.4	154.9	152.8	135.1	98.2	1,176.0
HUDS	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
LIND	1.3	0.0	0.9	0.1	0.0	0.2	0.0	0.0	0.4	2.9
NEPT	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.3
NYIS	145.4	112.5	144.9	110.2	119.4	154.6	152.8	135.0	97.6	1,172.4
TVA	294.6	392.4	293.9	413.5	367.4	251.6	399.8	325.5	410.4	3,149.0
Total	1,911.6	1,573.9	1,236.6	1,842.8	1,217.9	1,017.1	1,251.4	1,069.2	1,208.0	12,328.6

Table 9-5 Real-time scheduled gross export volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	187.5	85.1	68.6	30.7	31.8	49.4	51.8	27.1	45.1	577.1
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9
DUK	317.3	62.4	165.5	82.1	90.7	123.8	248.6	114.9	80.8	1,286.0
LGEE	120.9	99.7	128.3	88.2	55.2	119.7	131.7	132.5	90.7	966.8
MISO	1,904.2	1,426.4	1,756.8	1,511.6	2,257.6	2,371.3	2,662.0	3,461.1	2,373.8	19,724.8
ALTE	139.0	151.0	167.5	79.4	217.4	270.8	352.2	459.1	162.7	1,999.2
ALTW	19.1	18.4	28.1	17.7	23.1	40.3	32.0	58.1	46.4	283.1
AMIL	3.2	12.2	10.5	28.1	107.7	71.4	41.2	62.5	36.5	373.3
CIN	920.8	615.4	676.4	305.1	661.9	838.0	1,206.1	1,414.2	879.3	7,517.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	2.4	13.6	22.9	18.2	104.5	40.6	30.8	56.1	54.6	343.9
MEC	487.0	386.2	458.7	622.5	673.7	600.9	543.8	654.1	634.3	5,061.2
MECS	108.7	96.4	207.9	108.3	249.5	334.0	284.8	492.9	375.4	2,257.8
NIPS	72.0	44.9	74.0	277.3	103.0	63.9	47.7	58.8	53.1	794.6
WEC	152.2	88.4	110.8	55.0	116.8	111.3	123.4	205.2	131.4	1,094.6
NYISO	2,014.4	2,349.9	2,222.1	1,371.0	1,571.3	1,631.8	1,894.7	2,117.2	1,873.7	17,046.1
HUDS	173.6	275.2	342.4	258.9	178.4	368.7	456.8	438.4	410.1	2,902.5
LIND	212.1	209.6	221.9	148.9	210.8	206.8	229.0	227.7	203.7	1,870.6
NEPT	493.1	450.8	478.3	419.7	400.4	471.1	501.0	471.5	473.4	4,159.2
NYIS	1,135.5	1,414.4	1,179.5	543.4	781.7	585.2	707.9	979.6	786.5	8,113.8
TVA	391.8	306.9	108.9	425.0	143.5	323.4	358.6	280.4	189.1	2,527.5
Total	4,936.0	4,330.4	4,450.2	3,508.6	4,150.2	4,619.2	5,347.6	6,133.1	4,654.1	42,129.3

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[7] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SOUTH interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[8]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[9] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-20 presents the interface pricing points used in the first nine months of 2025. On October 21, 2020, PJM updated the mappings of external balancing authorities to individual pricing points. Figure 9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that the balancing authorities in the Western Interconnection are mapped to either the MISO interface pricing point or the SOUTH interface pricing point. This determination was made by PJM based on geographic location rather than the electrical impact on the PJM system. When power is scheduled across a DC tie line, its effects on the PJM system are as if a generator is located at the point

7 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

8 See the *2007 Annual State of the Market Report for PJM*, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

9 See "Interface Pricing Point Assignment Methodology," (May 7, 2025) <https://www.pjm.com/-/media/DotCom/etools/exschedule/interface-pricing-point-assignment-methodology.pdf>. PJM periodically updates these definitions on its website.

in the Eastern Interconnection where the DC tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ based on the relevant DC tie line and could vary from the MISO interface pricing point to the SOUTH interface pricing point. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM rather than geographical location. The MMU recommends that PJM review the mappings of external balancing authority pricing points at least annually to reflect the fact that changes to the system topology can affect the electrical impact of external power sources on PJM.

The MMU has made multiple recommendations to either retire or consolidate interface pricing points used by PJM. The reasons for those recommendations include: pricing points that could no longer be used to price actual transactions; pricing points that were inappropriately used to support special agreements; pricing points that were treated as multiple pricing points when they were a single pricing point; and pricing points that were noncontiguous to the PJM footprint that created opportunities for sham scheduling. Table 9-6 shows the interface pricing points, the recommendation and the date the recommendation was adopted.

Table 9-6 MMU interface pricing point recommendations and dates adopted

Interface Pricing Point	Recommendation	Date Adopted
IMO	Retire Pricing Point - Noncontiguous	
Southeast (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
Southwest (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
SOUTHEXP	Consolidate Pricing Points	1-Jun-2021
SOUTHIMP	Consolidate Pricing Points	1-Jun-2021
Southeast	Retire Pricing Point - Support Special Agreements	15-Apr-2021
Southwest	Retire Pricing Point - Support Special Agreements	15-Apr-2021
NCMPAEXP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
NCMPAIMP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
Northwest	Retire Pricing Point - Noncontiguous	1-Oct-2020
CPLEEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
CPLEIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
NIPSCO	Retire Pricing Point - Obsolete (Integration into MISO)	1-Jun-2020
OVEC	Retire Pricing Point - Obsolete (Integration into PJM)	1-Dec-2018

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[10] The MMU recommended that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. At the March 20, 2024, meeting of the Markets and Reliability Committee, PJM stakeholders approved the implementation of a new annual review of interface pricing definitions.[11] [12] The annual review evaluates, and adjusts as necessary, the interface pricing definitions to ensure the buses and weightings used in the interface pricing definitions capture changes in system topology over time and reflect current system conditions.

The contract transmission path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag

10 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.
11 *See* "Manual 11 Revisions – Interface Pricing Points Review," Presented at the PJM Markets and Reliability Committee (MRC) meeting held on March 20, 2024 <https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240320/20240320-consent-agenda-b---1-manual-11-revisions-interface-pricing-points---presentation.ashx>.
12 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 136 (October 1, 2025.

path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag.

In the real-time energy market, in the first nine months of 2025, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions. The top three net exporting interface pricing points in the real-time energy market accounted for 85.6 percent of the total net scheduled exports: PJM/MISO with 52.2 percent, PJM/NYIS with 20.9 percent and PJM/NEPTUNE with 12.5 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 47.8 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first nine months of 2025, there were net scheduled imports at two of PJM's seven interface pricing points eligible for real-time transactions. The top importing interface pricing point in the real-time energy market was the PJM/SOUTH interface pricing point, which accounted for 80.5 percent of the total net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the real-time energy market.

Table 9-7 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	190.3	28.7	76.9	109.4	27.4	91.9	93.3	13.2	35.5	666.5
MISO	(1,550.7)	(1,168.6)	(1,486.9)	(1,136.8)	(2,067.2)	(2,125.5)	(2,422.4)	(3,252.4)	(2,142.5)	(17,353.0)
NYISO	(1,852.9)	(2,237.3)	(2,076.4)	(1,263.4)	(1,453.9)	(1,477.5)	(1,740.6)	(1,982.2)	(1,776.1)	(15,860.2)
HUDSONTP	(173.6)	(275.1)	(342.4)	(258.9)	(178.4)	(368.7)	(456.8)	(438.3)	(410.0)	(2,902.2)
LINDENVFT	(210.9)	(209.6)	(221.1)	(148.8)	(210.8)	(206.6)	(229.0)	(227.7)	(203.3)	(1,867.7)
NEPTUNE	(493.1)	(450.8)	(478.2)	(419.7)	(400.4)	(471.1)	(501.0)	(471.4)	(473.3)	(4,158.9)
NYIS	(975.3)	(1,301.9)	(1,034.8)	(436.0)	(664.3)	(431.1)	(553.7)	(844.8)	(689.5)	(6,931.4)
SOUTH	188.8	620.8	272.8	625.0	561.4	(90.9)	(26.5)	157.5	437.0	2,746.0
Total	(3,024.5)	(2,756.5)	(3,213.6)	(1,665.8)	(2,932.2)	(3,602.1)	(4,096.1)	(5,063.9)	(3,446.1)	(29,800.7)

Table 9-8 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	238.1	65.6	78.1	110.0	29.9	99.3	105.4	33.7	42.1	802.1
MISO	233.4	188.9	256.2	360.9	182.6	236.2	225.7	181.5	221.7	2,087.1
NYISO	146.3	111.8	145.6	107.4	117.1	153.2	152.1	134.8	97.6	1,165.9
HUDSONTP	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
LINDENVFT	1.3	0.0	0.9	0.1	0.0	0.2	0.0	0.0	0.4	2.9
NEPTUNE	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.3
NYIS	145.0	111.7	144.5	107.2	117.1	153.0	152.1	134.7	97.0	1,162.4
SOUTH	1,293.8	1,207.7	756.8	1,264.5	888.3	528.4	768.2	719.2	846.7	8,273.4
Total	1,911.6	1,573.9	1,236.6	1,842.8	1,217.9	1,017.1	1,251.4	1,069.2	1,208.0	12,328.6

Table 9-9 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	47.8	36.9	1.2	0.6	2.5	7.4	12.1	20.4	6.6	135.6
MISO	1,784.1	1,357.4	1,743.1	1,497.7	2,249.8	2,361.8	2,648.1	3,434.0	2,364.2	19,440.2
NYISO	1,999.2	2,349.1	2,222.0	1,370.8	1,571.0	1,630.7	1,892.7	2,117.0	1,873.7	17,026.1
HUDSONTP	173.6	275.2	342.4	258.9	178.4	368.7	456.8	438.4	410.1	2,902.5
LINDENVFT	212.1	209.6	221.9	148.9	210.8	206.8	229.0	227.7	203.7	1,870.6
NEPTUNE	493.1	450.8	478.3	419.7	400.4	471.1	501.0	471.5	473.4	4,159.2
NYIS	1,120.3	1,413.6	1,179.3	543.3	781.4	584.1	705.9	979.5	786.5	8,093.8
SOUTH	1,105.0	587.0	483.9	639.4	326.9	619.3	794.7	561.6	409.6	5,527.4
Total	4,936.0	4,330.4	4,450.2	3,508.6	4,150.2	4,619.2	5,347.6	6,133.1	4,654.1	42,129.3

Day-Ahead Interface Imports and Exports

In the day-ahead energy market, as in the real-time energy market, scheduled imports and exports are determined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the day-ahead energy market requires fewer steps than in the real-time energy market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the real-time energy market.[13] Day-ahead energy market schedules need to be cleared through the day-ahead energy market process in order to become an approved schedule. The day-ahead energy market transactions are financially binding, but will not physically flow unless they are also submitted in the real-time energy market. In the day-ahead energy market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up to congestion; and dispatchable.[14]

In the day-ahead energy market, transaction sources and sinks are determined solely by market participants. In Table 9-10, Table 9-11, and Table 9-12, the scheduled interface designation is determined by the transmission reservation that was acquired and associated with the day-ahead market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SOUTH as the import pricing point when submitting the transaction in the day-ahead energy market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled interface pricing point tables, the import transaction would appear as scheduled through the SOUTH interface pricing point, which reflects the expected power flow.

Table 9-10 through Table 9-12 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the day-ahead energy market is shown by interface for the first nine months of 2025 in Table 9-10, while gross scheduled imports and exports are shown in Table 9-11 and Table 9-12.

In the day-ahead energy market, in the first nine months of 2025, there were net scheduled exports at 15 of PJM's 19 interfaces. The top three net exporting

13 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.
14 See the *2010 Annual State of the Market Report for PJM*, Volume 2, Section 4, "Interchange Transactions," for details.

interfaces in the day-ahead energy market accounted for 53.1 percent of the total net scheduled exports: PJM/NYISO (NYIS) with 21.9 percent, PJM/MidAmerican Energy Company (MEC) with 15.9 percent and PJM/Neptune (NEPT) with 15.3 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 50.2 percent of the total net PJM scheduled exports in the day-ahead energy market. In the first nine months of 2025, there were net exports in the day-ahead energy market at eight of the 10 separate interfaces that connect PJM to MISO. Those eight interfaces represented 39.3 percent of the total net PJM exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2025, there were net scheduled imports at two of PJM's 19 interfaces. The top importing interface in the day-ahead energy market was the Duke (DUK) Interface, which accounted for 70.0 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the day-ahead energy market. In the first nine months of 2025, there were net imports in the day-ahead energy market at one of the 10 separate interfaces that connect PJM to MISO (Indianapolis Power & Light). That interface represented 30.0 percent of the total net PJM imports in the day-ahead energy market.[15]

Table 9-10 Day-ahead scheduled net interchange volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(66.5)	(24.2)	(59.4)	(8.8)	(9.7)	(32.4)	(38.1)	(9.2)	(21.8)	(270.1)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	(87.2)	106.4	(21.5)	6.0	49.9	5.8	16.7	36.3	75.0	187.5
LGEE	(123.6)	(99.6)	(127.6)	(87.9)	(56.3)	(115.7)	(116.2)	(136.1)	(94.6)	(957.5)
MISO	(949.4)	(897.0)	(929.6)	(943.6)	(1,283.6)	(1,346.1)	(1,439.5)	(1,733.7)	(1,288.7)	(10,811.1)
ALTE	(53.6)	(51.0)	(79.0)	(25.9)	(149.9)	(192.7)	(192.4)	(114.0)	(39.3)	(897.8)
ALTW	(13.2)	(16.7)	(11.7)	(1.9)	(23.6)	(35.7)	(24.8)	(45.4)	(36.8)	(209.8)
AMIL	0.0	0.0	0.0	0.0	0.0	(1.0)	0.0	0.0	(0.5)	(1.5)
CIN	(351.8)	(420.6)	(381.9)	(153.0)	(408.6)	(417.1)	(606.4)	(836.2)	(534.4)	(4,110.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	3.7	27.3	0.4	0.5	20.5	12.3	15.5	80.2
MEC	(408.5)	(331.5)	(348.7)	(507.3)	(585.1)	(589.9)	(516.2)	(549.2)	(560.5)	(4,396.9)
MECS	14.1	(9.0)	(22.4)	(24.8)	(3.9)	(5.3)	(9.5)	(41.1)	(34.3)	(136.4)
NIPS	(23.8)	(12.3)	(16.7)	(240.3)	(17.0)	(18.9)	(19.8)	(17.8)	(10.3)	(377.0)
WEC	(112.6)	(55.8)	(72.8)	(17.6)	(95.8)	(86.0)	(91.0)	(142.2)	(88.0)	(761.8)
NYISO	(1,605.1)	(1,982.1)	(1,928.0)	(1,131.6)	(1,260.0)	(1,345.7)	(1,531.0)	(1,690.4)	(1,433.1)	(13,906.9)
HUDS	(170.4)	(272.3)	(362.5)	(262.8)	(166.8)	(358.2)	(456.0)	(427.9)	(411.0)	(2,887.9)
LIND	(74.8)	(82.0)	(84.1)	(51.0)	(80.2)	(79.8)	(91.0)	(96.2)	(71.6)	(710.9)
NEPT	(484.9)	(454.3)	(494.4)	(436.3)	(416.0)	(482.8)	(501.4)	(490.3)	(480.0)	(4,240.3)
NYIS	(874.9)	(1,173.6)	(986.9)	(381.5)	(597.0)	(424.9)	(482.7)	(676.0)	(470.6)	(6,067.9)
TVA	(298.0)	(190.8)	(87.9)	(309.0)	(28.4)	(221.2)	(242.2)	(205.3)	(88.6)	(1,671.4)
Total without Up To Congestion	(3,129.7)	(3,087.2)	(3,153.9)	(2,474.9)	(2,588.0)	(3,055.3)	(3,350.4)	(3,738.4)	(2,851.7)	(27,429.6)
Up To Congestion	(237.1)	211.1	91.2	180.8	50.6	297.1	411.9	373.8	(180.4)	1,199.0
Total	(3,366.8)	(2,876.2)	(3,062.7)	(2,294.2)	(2,537.4)	(2,758.2)	(2,938.4)	(3,364.6)	(3,032.1)	(26,230.6)

15 In the day-ahead energy market, two PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light West (CPLW and PJM/City Water Light & Power (CWLP)).

Table 9-11 Day-ahead scheduled gross import volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	1.0	17.2	0.0	16.3	14.0	3.1	0.0	10.7	12.2	74.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	42.2	130.2	74.3	45.7	76.5	50.7	80.4	70.4	97.6	668.0
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.0	1.6
MISO	50.9	20.3	56.7	88.8	16.3	35.0	56.8	19.2	54.5	398.5
ALTE	5.4	3.7	7.6	6.7	5.0	2.6	1.4	0.7	1.5	34.7
ALTW	1.3	0.3	8.2	10.0	0.0	5.9	6.1	2.0	2.9	36.7
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	27.9	3.5	32.3	20.0	9.3	25.6	18.7	2.6	24.1	164.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	3.7	27.3	0.4	0.5	20.5	13.6	19.4	85.3
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MECS	15.3	0.1	1.2	0.8	0.0	0.4	3.2	0.3	4.9	26.2
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	1.0	12.7	3.7	24.1	1.6	0.0	6.9	0.0	1.7	51.6
NYISO	32.7	0.9	0.6	3.9	3.3	10.5	4.3	0.3	0.5	56.9
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.7	0.0	0.0	0.1	0.0	0.3	0.0	0.0	0.5	1.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	32.0	0.9	0.6	3.8	3.3	10.2	4.3	0.3	0.0	55.2
TVA	11.0	69.3	5.7	98.3	93.5	32.1	69.2	51.8	56.0	487.1
Total without Up To Congestion	137.8	237.8	137.3	253.0	203.7	131.4	210.8	154.0	220.7	1,686.5
Up To Congestion	572.1	893.3	831.6	547.2	483.9	671.9	753.2	802.0	404.4	5,959.6
Total	710.0	1,131.1	968.8	800.3	687.6	803.3	964.0	956.0	625.0	7,646.1

Table 9-12 Day-ahead scheduled gross export volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	67.5	41.4	59.4	25.1	23.7	35.5	38.2	20.0	33.9	344.6
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	129.4	23.8	95.8	39.8	26.5	44.9	63.7	34.1	22.6	480.6
LGEE	123.6	99.6	127.6	87.9	56.3	115.7	116.2	137.6	94.6	959.0
MISO	1,000.3	917.2	986.3	1,032.4	1,299.9	1,381.1	1,496.3	1,753.0	1,343.1	11,209.6
ALTE	59.0	54.7	86.7	32.6	155.0	195.2	193.8	114.7	40.8	932.5
ALTW	14.5	17.0	19.9	11.9	23.6	41.6	30.9	47.4	39.7	246.4
AMIL	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.5	1.5
CIN	379.7	424.1	414.2	173.0	417.9	442.8	625.1	838.8	558.5	4,274.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	3.9	5.1
MEC	408.5	331.5	348.7	507.3	585.1	589.9	516.2	549.2	560.5	4,396.9
MECS	1.2	9.1	23.6	25.6	4.0	5.7	12.6	41.4	39.2	162.6
NIPS	23.8	12.3	16.7	240.3	17.0	18.9	19.8	17.8	10.3	377.0
WEC	113.6	68.5	76.5	41.7	97.4	86.0	97.9	142.2	89.7	813.5
NYISO	1,637.8	1,983.0	1,928.5	1,135.5	1,263.3	1,356.3	1,535.3	1,690.6	1,433.6	13,963.8
HUDS	170.4	272.3	362.5	262.8	166.8	358.2	456.0	427.9	411.0	2,887.9
LIND	75.6	82.0	84.1	51.1	80.2	80.1	91.0	96.2	72.1	712.5
NEPT	484.9	454.3	494.4	436.3	416.0	482.8	501.4	490.3	480.0	4,240.3
NYIS	906.9	1,174.4	987.5	385.3	600.3	435.1	486.9	676.3	470.6	6,123.1
TVA	308.9	260.1	93.6	407.4	121.9	253.3	311.4	257.2	144.6	2,158.4
Total without Up To Congestion	3,267.5	3,325.0	3,291.2	2,727.9	2,791.7	3,186.8	3,561.2	3,892.4	3,072.4	29,116.1
Up To Congestion	809.2	682.3	740.3	366.5	433.3	374.7	341.3	428.2	584.8	4,760.6
Total	4,076.8	4,007.3	4,031.5	3,094.4	3,225.0	3,561.5	3,902.4	4,320.6	3,657.2	33,876.7

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-13 through Table 9-18 show the day-ahead scheduled interchange totals at the interface pricing points. In the first nine months of 2025, up to congestion transactions accounted for 77.9 percent of all scheduled import MW transactions and 14.1 percent of all scheduled export MW transactions in the day-ahead energy market. The day-ahead net scheduled interchange in the first nine months of 2025, including up to congestion transactions, is shown by interface pricing point in Table 9-13. Scheduled up to congestion transactions by interface pricing point in the first nine months of 2025 are shown in Table 9-14. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-15 and Table 9-17, while gross scheduled import and export up to congestion transactions are shown in Table 9-16 and Table 9-18.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. PJM should immediately eliminate interface pricing points when changes to the market mean that the pricing points can no longer be used to price actual transactions and do not reflect actual price formation.

In the day-ahead energy market, in the first nine months of 2025, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the day-ahead energy market accounted for 78.6 percent of the total net scheduled exports: PJM/MISO with 36.8 percent, PJM/NYIS with 26.0 percent and PJM/NEPTUNE (NEPT) with 15.8 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 59.2 percent of the total net PJM scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2025, there were net scheduled imports at one of PJM's seven interface pricing points eligible for day-ahead transactions, (Ontario Independent Electricity System Operator (IMO)), which accounted for 100.0 percent of the net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2025, up to congestion transactions had net scheduled exports at three of PJM's seven interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 87.9 percent of the total net up to congestion scheduled exports: PJM/NYIS with 44.6 percent and PJM/HUDSONTP with 43.3 percent of the net up to congestion scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 100.0 percent of the total net scheduled up to congestion exports in the day-ahead energy market. However, the PJM/NEPTUNE interface pricing point had net up to congestion scheduled imports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2025, up to congestion transactions had net scheduled imports at four of PJM's seven interface pricing points eligible for day-ahead transactions. The top two importing interface pricing points eligible for up to congestion transactions accounted for 95.6 percent of the total up to congestion scheduled imports: PJM/SOUTH with 57.1 percent and PJM/MISO with 38.6 percent of the net up to congestion scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 2.8 percent of the total net scheduled up to congestion imports in the day-ahead energy market. However, the PJM/HUDSONTP, PJM/LINDENVFT and PJM/NYIS interface pricing points had net up to congestion scheduled exports in the day-ahead energy market.

Table 9-13 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	(29.4)	32.3	1.7	5.5	(8.7)	21.2	10.2	27.5	5.4	65.7
MISO	(921.5)	(817.6)	(910.6)	(927.7)	(1,280.1)	(1,121.2)	(1,041.1)	(1,352.7)	(1,297.8)	(9,670.3)
NYISO	(1,820.3)	(2,221.0)	(2,306.1)	(1,236.2)	(1,359.3)	(1,480.2)	(1,640.6)	(1,808.9)	(1,689.6)	(15,562.2)
HUDSONTP	(283.5)	(478.9)	(484.5)	(314.8)	(191.3)	(406.7)	(493.4)	(487.8)	(501.9)	(3,643.0)
LINDENVFT	(110.8)	(138.1)	(135.4)	(60.3)	(82.8)	(91.4)	(95.3)	(103.2)	(104.8)	(922.1)
NEPTUNE	(482.1)	(427.9)	(477.2)	(425.1)	(426.1)	(486.3)	(490.5)	(472.4)	(471.5)	(4,159.1)
NYIS	(943.9)	(1,176.1)	(1,208.9)	(435.9)	(659.2)	(495.9)	(561.4)	(745.4)	(611.4)	(6,838.0)
SOUTH	(595.6)	130.1	152.3	(135.8)	110.7	(177.9)	(267.0)	(230.5)	(50.2)	(1,063.9)
Total	(3,366.8)	(2,876.2)	(3,062.7)	(2,294.2)	(2,537.4)	(2,758.2)	(2,938.4)	(3,364.6)	(3,032.1)	(26,230.6)

Table 9-14 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	(45.5)	39.3	1.0	4.8	(8.7)	18.8	6.1	29.5	2.0	47.3
MISO	18.4	65.4	19.7	17.8	8.1	227.3	407.2	376.8	(5.7)	1,135.0
NYISO	(216.5)	(238.9)	(378.1)	(104.7)	(103.9)	(134.5)	(110.2)	(118.5)	(256.5)	(1,661.8)
HUDSONTP	(113.1)	(206.7)	(122.0)	(52.0)	(24.5)	(48.5)	(37.4)	(60.0)	(90.9)	(755.1)
LINDENVFT	(35.9)	(56.1)	(51.3)	(9.3)	(2.6)	(11.6)	(4.3)	(7.0)	(33.1)	(211.2)
NEPTUNE	2.8	26.4	17.3	11.1	(10.1)	(3.4)	10.9	17.8	8.4	81.2
NYIS	(70.3)	(2.5)	(222.0)	(54.5)	(66.7)	(71.1)	(79.4)	(69.4)	(140.8)	(776.7)
SOUTH	6.6	345.2	448.6	262.8	155.1	185.6	108.8	86.0	79.8	1,678.5
Total Interfaces	(237.1)	211.1	91.2	180.8	50.6	297.1	411.9	373.8	(180.4)	1,199.0
INTERNAL	6,876.8	6,633.5	6,391.0	5,294.5	5,044.3	6,988.4	6,118.3	5,580.2	6,174.4	55,101.4
Total	6,639.7	6,844.6	6,482.3	5,475.2	5,094.9	7,285.5	6,530.2	5,954.0	5,994.0	56,300.5

Table 9-15 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	48.1	60.7	16.4	11.6	13.5	29.2	24.1	39.8	30.2	273.7
MISO	161.6	277.7	243.4	285.1	238.0	377.4	516.7	536.4	249.0	2,885.3
NYISO	151.9	172.5	129.3	45.2	52.0	71.0	100.7	104.6	77.2	904.3
HUDSONTP	7.1	4.4	26.9	8.9	13.3	8.6	16.5	13.6	18.1	117.3
LINDENVFT	6.1	13.0	22.9	4.9	5.7	6.2	14.6	19.8	8.7	102.1
NEPTUNE	19.1	43.3	50.9	18.1	4.2	10.9	17.4	24.8	19.6	208.4
NYIS	119.5	111.8	28.6	13.3	28.7	45.2	52.2	46.4	30.9	476.5
SOUTH	348.4	620.2	579.7	458.3	384.2	325.7	322.4	275.2	268.7	3,582.9
Total	710.0	1,131.1	968.8	800.3	687.6	803.3	964.0	956.0	625.0	7,646.1

Table 9-16 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	30.4	60.6	15.8	10.9	13.5	26.4	18.4	39.5	25.3	240.7
MISO	128.4	257.5	187.4	198.8	221.7	345.2	472.5	517.5	199.4	2,528.4
NYISO	119.1	171.6	128.7	41.3	48.7	60.4	96.4	104.3	76.7	847.4
HUDSONTP	7.1	4.4	26.9	8.9	13.3	8.6	16.5	13.6	18.1	117.3
LINDENVFT	5.4	13.0	22.9	4.8	5.7	5.9	14.6	19.8	8.2	100.5
NEPTUNE	19.1	43.3	50.9	18.1	4.2	10.9	17.4	24.8	19.6	208.4
NYIS	87.5	110.9	28.0	9.5	25.4	34.9	47.9	46.1	30.9	421.2
SOUTH	294.2	403.6	499.6	296.2	200.1	239.8	165.9	140.7	102.9	2,343.1
Total Interfaces	572.1	893.3	831.6	547.2	483.9	671.9	753.2	802.0	404.4	5,959.6

Table 9-17 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	77.5	28.4	14.7	6.1	22.2	8.1	13.9	12.4	24.8	208.0
MISO	1,083.1	1,095.3	1,154.0	1,212.8	1,518.1	1,498.6	1,557.9	1,889.1	1,546.7	12,555.5
NYISO	1,972.2	2,393.4	2,435.4	1,281.5	1,411.3	1,551.2	1,741.3	1,913.4	1,766.8	16,466.4
HUDSONTP	290.6	483.3	511.4	323.7	204.6	415.3	509.9	501.4	520.0	3,760.2
LINDENVFT	116.9	151.1	158.4	65.3	88.5	97.6	109.9	123.1	113.4	1,024.2
NEPTUNE	501.2	471.2	528.1	443.3	430.3	497.2	507.9	497.2	491.1	4,367.5
NYIS	1,063.4	1,287.8	1,237.5	449.2	687.9	541.0	613.6	791.8	642.3	7,314.5
SOUTH	944.0	490.1	427.5	594.1	273.5	503.7	589.4	505.7	318.9	4,646.8
Total	4,076.8	4,007.3	4,031.5	3,094.4	3,225.0	3,561.5	3,902.4	4,320.6	3,657.2	33,876.7

Table 9-18 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	75.9	21.3	14.7	6.1	22.2	7.6	12.3	10.0	23.3	193.5
MISO	110.0	192.1	167.7	181.0	213.6	117.9	65.3	140.7	205.1	1,393.4
NYISO	335.7	410.5	506.8	146.0	152.5	195.0	206.6	222.8	333.2	2,509.2
HUDSONTP	120.2	211.0	148.9	60.9	37.8	57.1	53.9	73.5	109.0	872.4
LINDENVFT	41.3	69.1	74.2	14.1	8.3	17.5	18.9	26.8	41.4	311.7
NEPTUNE	16.3	17.0	33.7	7.0	14.3	14.3	6.5	6.9	11.1	127.2
NYIS	157.8	113.4	250.0	64.0	92.1	106.0	127.3	115.5	171.7	1,197.9
SOUTH	287.6	58.3	51.1	33.4	45.0	54.2	57.0	54.7	23.2	664.6
Total Interfaces	809.2	682.3	740.3	366.5	433.3	374.7	341.3	428.2	584.8	4,760.6

Table 9-19 Active scheduling interfaces: January through September, 2025[16]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-3 PJM's footprint and its external scheduling interfaces

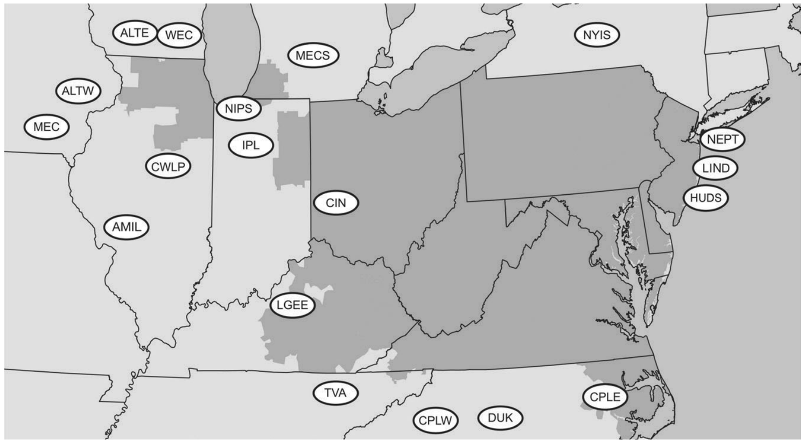
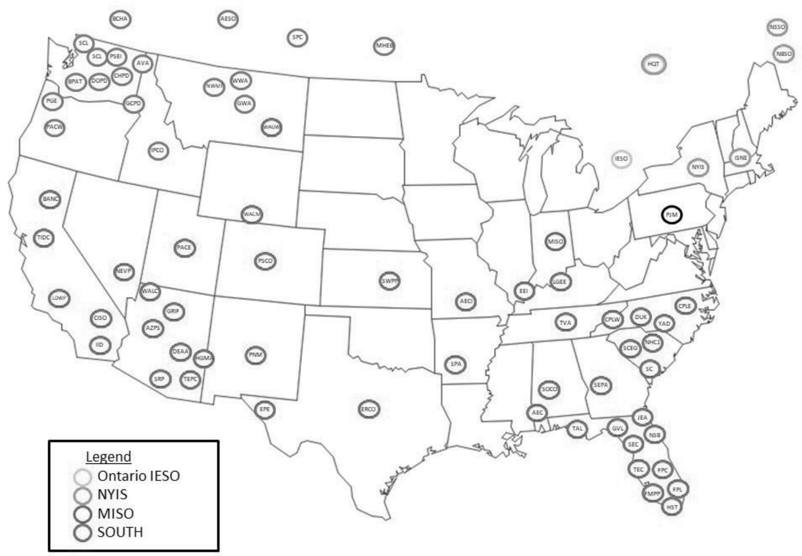


Table 9-20 Active scheduled interface pricing points: January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTH	Active	Active	Active	Active	Active	Active	Active	Active	Active

16 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of September 30, 2025, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Figure 9-4 External balancing authority default interface pricing point assignments



Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[17]

17 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market-based price differentials at interface pricing points that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at PJM's borders. For example, if a 100 MW transaction were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Correspondingly, there would be no scheduled flows at the PJM/SOUTH interface border, but there would be 100 MW of actual flows on the interface. In the first nine months of 2025, of the 2,746.0 GWh of net scheduled interchange that received the SOUTH interface pricing point, 1,622.6 GWh (59.1 percent) were scheduled through MISO. There were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In the first nine months of 2025, net scheduled interchange was -29,800.7 GWh and net actual interchange was -29,592.4 GWh, a difference of 208.4 GWh. In the first nine months of 2024, net scheduled interchange was -27,542.0 GWh and net actual interchange was -27,738.4 GWh, a difference of 196.4 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange by using unilateral or bilateral paybacks. Inadvertent interchange accumulations that are paid back unilaterally are paid by controlling to a non-zero area control error (ACE). For example, Table 9-21 shows that PJM had 208.4 GW of inadvertent interchange in the first nine months of 2025. To reduce this inadvertent interchange, PJM can control to an ACE less than zero, which would result in under generating. By way of the power balance equation, power would flow into PJM from its neighboring balancing authority areas. This would create decreased actual exports that were not scheduled, thus reducing the overall inadvertent. To maintain reliability, unilateral paybacks are accounted for in the control performance standard calculations. Bilateral paybacks are scheduled with other balancing authority areas by scheduling a correction and incorporating that amount as a bias in the energy management system.[18] [19]

Table 9-21 shows that in the first nine months of 2025, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -799.7 GWh of net scheduled interchange and -8,409.3 GWh of net actual interchange, a difference of 7,609.6 GWh.

18 See PJM. "Manual 12: Balancing Operations," Rev. 56 (October 1, 2025).
19 PJM does not publish data on inadvertent payback.

Table 9-21 Net scheduled and actual PJM flows by interface (GWh): January through September, 2025

Interface	Actual	Net Scheduled	Difference (GWh)
CPLE	881.9	(215.2)	1,097.1
CPLW	(109.2)	(0.1)	(109.1)
DUK	1,442.1	1,341.5	100.6
LGEE	1,318.1	(625.5)	1,943.6
MISO	(20,391.4)	(15,052.8)	(5,338.6)
ALTE	(805.4)	(1,844.8)	1,039.3
ALTW	(2,804.7)	(171.6)	(2,633.1)
AMIL	(3,472.6)	1,058.8	(4,531.3)
CIN	(3,291.7)	(6,653.6)	3,362.0
CWLP	(216.2)	0.0	(216.2)
IPL	(1,539.7)	152.0	(1,691.8)
MEC	(6,113.9)	(4,687.0)	(1,426.9)
MECS	3,497.7	(1,260.3)	4,758.0
NIPS	(8,409.3)	(799.7)	(7,609.6)
WEC	2,764.5	(846.5)	3,611.0
NYISO	(15,736.2)	(15,870.2)	134.0
HUDS	(2,902.2)	(2,902.2)	0.0
LIND	(1,867.7)	(1,867.7)	0.0
NEPT	(4,158.9)	(4,158.9)	0.0
NYIS	(6,807.4)	(6,941.4)	134.0
TVA	3,002.4	621.5	2,380.9
Total	(29,592.4)	(29,800.7)	208.4

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[20] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SOUTH interface pricing point net schedule totals because SPP is mapped to the SOUTH interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

20 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path. Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Table 9-22 shows actual flows associated with the IMO interface pricing point as zero because there is no PJM/IMO Interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-22 shows that in the first nine months of 2025, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 2,746.0 GWh of net scheduled interchange and 6,535.3 GWh of net actual interchange, a difference of 3,789.3 GWh.

Table 9-22 PJM flows by interface pricing point (GWh): January through September, 2025

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
IMO	0.0	666.5	(666.5)
MISO	(20,391.4)	(17,353.0)	(3,038.4)
NYISO	(15,736.2)	(15,860.2)	124.0
HUDSONTP	(2,902.2)	(2,902.2)	0.0
LINDENVFT	(1,867.7)	(1,867.7)	0.0
NEPTUNE	(4,158.9)	(4,158.9)	0.0
NYIS	(6,807.4)	(6,931.4)	124.0
SOUTH	6,535.3	2,746.0	3,789.3
Total	(29,592.4)	(29,800.7)	208.4

Table 9-23 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the IMO entered the PJM energy market.

Table 9-23 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through September, 2025

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
MISO	(20,391.4)	(16,676.5)	(3,714.9)
NYISO	(15,736.2)	(15,870.2)	134.0
HUDSONTP	(2,902.2)	(2,902.2)	0.0
LINDENVFT	(1,867.7)	(1,867.7)	0.0
NEPTUNE	(4,158.9)	(4,158.9)	0.0
NYIS	(6,807.4)	(6,941.4)	134.0
SOUTH	6,535.3	2,746.0	3,789.3
Total	(29,592.4)	(29,800.7)	208.4

The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

PJM attempts to ensure that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game the markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loop flow would be reduced.

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-24 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the interface pricing points that were assigned to energy transactions that had paths at each of PJM's interfaces. For example, Table 9-24 shows that in the first nine months of 2025, the majority of imports to the PJM energy market for which a market participant specified Michigan Electric Coordinated System (MECS) as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the IMO Interface, and thus actual flows were assigned the IMO interface pricing point (593.9 GWh). The majority of exports from the PJM energy market for which a market participant specified MECS as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM energy market at the MISO Interface, and were assigned the MISO interface pricing point (-2,066.3 GWh).

Table 9-24 Net scheduled and actual flows by interface and interface pricing point (GWh): January through September, 2025

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(805.4)	(1,844.8)	1,039.3	LGEE		1,318.1	(625.5)	1,943.6
	IMO	0.0	1.1	(1.1)		SOUTH	1,318.1	(625.5)	1,943.6
	MISO	(805.4)	(1,839.0)	1,033.6	LIND		(1,867.7)	(1,867.7)	0.0
	SOUTH	0.0	(6.9)	6.9		LINDENVFT	(1,867.7)	(1,867.7)	0.0
ALTW		(2,804.7)	(171.6)	(2,633.1)	MEC		(6,113.9)	(4,687.0)	(1,426.9)
	IMO	0.0	14.0	(14.0)		IMO	0.0	(1.6)	1.6
	MISO	(2,804.7)	(196.6)	(2,608.1)		MISO	(6,113.9)	(4,676.8)	(1,437.1)
	SOUTH	0.0	11.0	(11.0)		SOUTH	0.0	(8.6)	8.6
AMIL		(3,472.6)	1,058.8	(4,531.3)	MECS		3,497.7	(1,260.3)	4,758.0
	MISO	(3,472.6)	(108.1)	(3,364.5)		IMO	0.0	593.9	(593.9)
	SOUTH	0.0	1,166.8	(1,166.8)		MISO	3,497.7	(2,066.3)	5,564.0
CIN		(3,291.7)	(6,653.6)	3,362.0		SOUTH	0.0	212.0	(212.0)
	IMO	0.0	(29.1)	29.1	NEPT		(4,158.9)	(4,158.9)	0.0
	MISO	(3,291.7)	(6,716.8)	3,425.1		NEPTUNE	(4,158.9)	(4,158.9)	0.0
	SOUTH	0.0	92.3	(92.3)	NIPS		(8,409.3)	(799.7)	(7,609.6)
CPLE		881.9	(215.2)	1,097.1		MISO	(8,409.3)	(799.7)	(7,609.6)
	SOUTH	881.9	(215.2)	1,097.1	NYIS		(6,807.4)	(6,941.4)	134.0
CPLW		(109.2)	(0.1)	(109.1)		IMO	0.0	(10.0)	10.0
	SOUTH	(109.2)	(0.1)	(109.1)		NYIS	(6,807.4)	(6,931.4)	124.0
CWLP		(216.2)	0.0	(216.2)	TVA		3,002.4	621.5	2,380.9
	MISO	(216.2)	0.0	(216.2)		MISO	0.0	(0.0)	0.0
DUK		1,442.1	1,341.5	100.6		SOUTH	3,002.4	621.5	2,380.9
	MISO	0.0	(1.1)	1.1	WEC		2,764.5	(846.5)	3,611.0
	SOUTH	1,442.1	1,342.6	99.5		MISO	2,764.5	(995.9)	3,760.4
HUDS		(2,902.2)	(2,902.2)	0.0		SOUTH	0.0	149.4	(149.4)
	HUDSONTP	(2,902.2)	(2,902.2)	0.0	Grand Total		(29,592.4)	(29,800.7)	208.4
IPL		(1,539.7)	152.0	(1,691.8)					
	IMO	0.0	98.2	(98.2)					
	MISO	(1,539.7)	47.2	(1,587.0)					
	SOUTH	0.0	6.6	(6.6)					

Table 9-25 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-24. Table 9-25 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-25 shows that in the first nine months of 2025, the majority of imports to the PJM energy market for which a market participant specified a generation control area for which it was assigned the SOUTH interface pricing point, had a path that entered the PJM energy market at the DUK Interface (1,342.6 GWh). The majority of exports from the PJM energy market for which a market participant specified a load control area for which it was assigned the SOUTH interface pricing point, had a path that would leave the PJM energy market at the LGEE Interface (-625.5 GWh).

Table 9-25 Net scheduled and actual flows by interface pricing point and interface (GWh): January through September, 2025

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
HUDSONTP		(2,902.2)	(2,902.2)	0.0	NEPTUNE		(4,158.9)	(4,158.9)	0.0
	HUDS	(2,902.2)	(2,902.2)	0.0		NEPT	(4,158.9)	(4,158.9)	0.0
IMO		0.0	666.5	(666.5)	NYIS		(6,807.4)	(6,931.4)	124.0
	ALTE	0.0	1.1	(1.1)		NYIS	(6,807.4)	(6,931.4)	124.0
	ALTW	0.0	14.0	(14.0)	SOUTH		6,535.3	2,746.0	3,789.3
	CIN	0.0	(29.1)	29.1		ALTE	0.0	(6.9)	6.9
	IPL	0.0	98.2	(98.2)		ALTW	0.0	11.0	(11.0)
	MEC	0.0	(1.6)	1.6		AMIL	0.0	1,166.8	(1,166.8)
	MECS	0.0	593.9	(593.9)		CIN	0.0	92.3	(92.3)
	NYIS	0.0	(10.0)	10.0		CPLE	881.9	(215.2)	1,097.1
LINDENVFT		(1,867.7)	(1,867.7)	0.0		CPLW	(109.2)	(0.1)	(109.1)
	LIND	(1,867.7)	(1,867.7)	0.0		DUK	1,442.1	1,342.6	99.5
MISO		(20,391.4)	(17,353.0)	(3,038.4)		IPL	0.0	6.6	(6.6)
	ALTE	(805.4)	(1,839.0)	1,033.6		LGEE	1,318.1	(625.5)	1,943.6
	ALTW	(2,804.7)	(196.6)	(2,608.1)		MEC	0.0	(8.6)	8.6
	AMIL	(3,472.6)	(108.1)	(3,364.5)		MECS	0.0	212.0	(212.0)
	CIN	(3,291.7)	(6,716.8)	3,425.1		TVA	3,002.4	621.5	2,380.9
	CWLP	(216.2)	0.0	(216.2)		WEC	0.0	149.4	(149.4)
	DUK	0.0	(1.1)	1.1	Grand Total		(29,592.4)	(29,800.7)	208.4
	IPL	(1,539.7)	47.2	(1,587.0)					
	MEC	(6,113.9)	(4,676.8)	(1,437.1)					
	MECS	3,497.7	(2,066.3)	5,564.0					
	NIPS	(8,409.3)	(799.7)	(7,609.6)					
	TVA	0.0	(0.0)	0.0					
	WEC	2,764.5	(995.9)	3,760.4					

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on nonmarket areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and nonmarket areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (nonmarket areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. The Commission required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[21]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data include the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[22]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. The available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed

21 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.
22 141 FERC ¶ 61,235 (2012).

from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

Area Control Error (ACE) Data

Area control error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual websites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU recommends, that in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. MISO's LMP calculations at the buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs.[23] The interface definitions led to questions about the level of congestion included in interchange pricing.

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on 10 ties composed of MISO and PJM monitored facilities. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Real-Time and Day-Ahead PJM/MISO Interface Prices

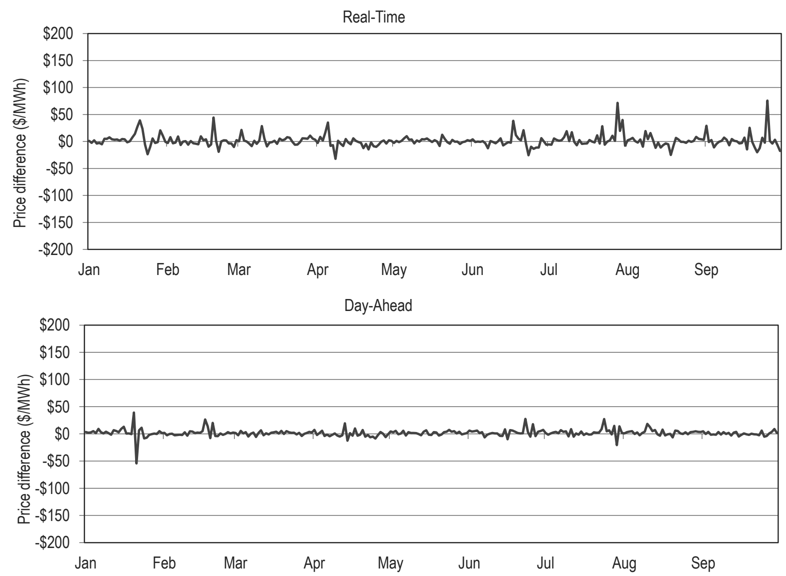
In the first nine months of 2025, the direction of flow was consistent with price differentials in 52.4 percent of the hours. Table 9-26 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Table 9-26 shows that PJM was a net exporter of energy to MISO in all but 125 hours during the first nine months of 2025. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first nine months of 2025, flows were in the uneconomic direction on the PJM/MISO interface in 47.6 percent of all hours. Figure 9-5 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

23 See "LMP Aggregate Definitions," (September 17, 2025) <https://www.pjm.com/-/media/DotCom/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.xlsx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

Table 9-26 PJM and MISO flow based hours and price differences: January through September, 2025

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	3,418	$15.02
	Consistent Flow (PJM to MISO)	3,362	$14.96
	Inconsistent Flow (MISO to PJM)	56	$18.75
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	3,133	$13.22
	Consistent Flow (MISO to PJM)	69	$13.27
	Inconsistent Flow (PJM to MISO)	3,064	$13.22
	No Flow	0	$0.00

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through September, 2025



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

Almost without exception, power flows from PJM to MISO regardless of the direction of price differences. In the first nine months of 2025, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 3,431 hours (52.4 percent of all hours), and was inconsistent with price differentials in 3,120 hours (47.6 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,120 hours where flows were in a direction inconsistent with price differences, 2,773 of those hours (88.9 percent) had a price difference greater than or equal to $1.00 and 1,745 of those hours (55.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,151.09. Of the 3,431 hours where flows were consistent with price differences, 3,022 of those hours (88.1 percent) had a price difference greater than or equal to $1.00 and 1,547 of all such hours (45.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,282.45.

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through September, 2025

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	3,120	100.0%	3,431	100.0%
$1.00	2,773	88.9%	3,022	88.1%
$5.00	1,745	55.9%	1,547	45.1%
$10.00	1,079	34.6%	871	25.4%
$15.00	724	23.2%	614	17.9%
$20.00	510	16.3%	452	13.2%
$25.00	373	12.0%	380	11.1%
$50.00	128	4.1%	187	5.5%
$75.00	64	2.1%	108	3.1%
$100.00	44	1.4%	74	2.2%
$200.00	9	0.3%	36	1.0%
$300.00	5	0.2%	17	0.5%
$400.00	4	0.1%	11	0.3%
$500.00	4	0.1%	10	0.3%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[24]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. On May 1, 2017, PJM modified the PJM/NYIS interface price to be based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

Prior to May 1, 2017, PJM's PJM/NYIS interface definition used two buses and included the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change.

The NYISO uses proxy buses to calculate interface prices with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21

24 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

Real-Time and Day-Ahead PJM/NYISO Interface Prices

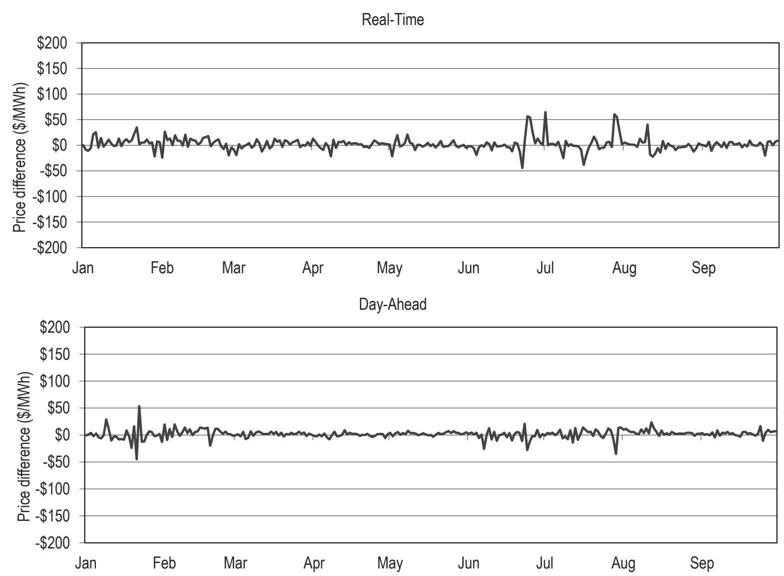
In the first nine months of 2025, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 59.2 percent of the hours in the first nine months of 2025. Table 9-28 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-6 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

Table 9-28 PJM and NYISO flow based hours and price differences: January through September, 2025[25]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	3,955	$16.45
	Consistent Flow (PJM to NYIS)	3,769	$14.47
	Inconsistent Flow (NYIS to PJM)	186	$56.49
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	2,596	$19.13
	Consistent Flow (NYIS to PJM)	108	$45.06
	Inconsistent Flow (PJM to NYIS)	2,488	$18.01
	No Flow	0	$0.00

25 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-6 Price differences (NY/PJM proxy - PJM/NYIS Interface): January through September, 2025



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first nine months of 2025, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,877 hours (59.2 percent of all hours), and was inconsistent with price differences in 2,674 hours (40.8 percent of all hours). Table 9-29 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 2,674 hours where flows were in a direction inconsistent with price differences, 2,456 of those hours (91.8 percent) had a price difference greater than or equal to $1.00 and 1,805 of all those hours (67.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $867.05. Of the 3,877 hours where flows were consistent with price differences, 3,646 of those hours (94.0 percent) had a price difference greater than or equal to $1.00 and 2,597 of all such hours (67.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,073.12.

Table 9-29 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through September, 2025

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	2,674	100.0%	3,877	100.0%
$1.00	2,456	91.8%	3,646	94.0%
$5.00	1,805	67.5%	2,597	67.0%
$10.00	1,245	46.6%	1,595	41.1%
$15.00	893	33.4%	1,016	26.2%
$20.00	678	25.4%	704	18.2%
$25.00	515	19.3%	553	14.3%
$50.00	209	7.8%	190	4.9%
$75.00	107	4.0%	87	2.2%
$100.00	70	2.6%	48	1.2%
$200.00	32	1.2%	14	0.4%
$300.00	20	0.7%	8	0.2%
$400.00	10	0.4%	6	0.2%
$500.00	5	0.2%	5	0.1%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-30, including average prices and measures of variability.

Table 9-30 PJM, NYISO and MISO border price averages: January through September, 2025[26]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$47.19	$38.04	$47.21	$38.54
	ISO Price at PJM Border	$49.61	$39.55	$49.15	$40.31
	Difference at Border (PJM-ISO)	($2.42)	($1.51)	($1.94)	($1.77)
	Average Absolute Value of Interval Difference at Border	$22.17	$18.68	$7.73	$6.21
	Sign Changes per Day	41.2	46.7	2.8	3.1
Standard Deviation	PJM Price at ISO Border	$68.54	$59.27	$34.66	$27.63
	ISO Price at PJM Border	$68.56	$80.39	$31.53	$26.65
	Difference at Border (PJM-ISO)	$69.40	$86.00	$12.64	$11.05

Neptune Underwater Transmission Line to Long Island, New York

The Neptune Line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. The flows were consistent with price differentials in 81.5 percent of the hours in the first nine months of 2025. Table 9-31 shows the number of hours and average hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

Table 9-31 PJM and NYISO flow based hours and price differences (Neptune): January through September, 2025

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	5,463	$31.17
	Consistent Flow (PJM to NYIS)	5,337	$31.54
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	126	$15.54
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	1,088	$19.79
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,065	$20.07
	No Flow	23	$6.81

26 Effective April 1, 2018, PJM implemented five minute LMP settlements in the real-time energy market. The sign changes per day represented in this table reflect the number of intervals where the sign changed per day. For the real-time energy market, there are 288 five minute intervals per day. For the day-ahead market there are 24 hourly intervals per day.

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line (“Out Service”) and another transmission service reservation is required on the Neptune HVDC Line (“Neptune Service”).[27] The PJM Out Service is covered by normal PJM OASIS business operations.[28] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On September 30, 2025, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

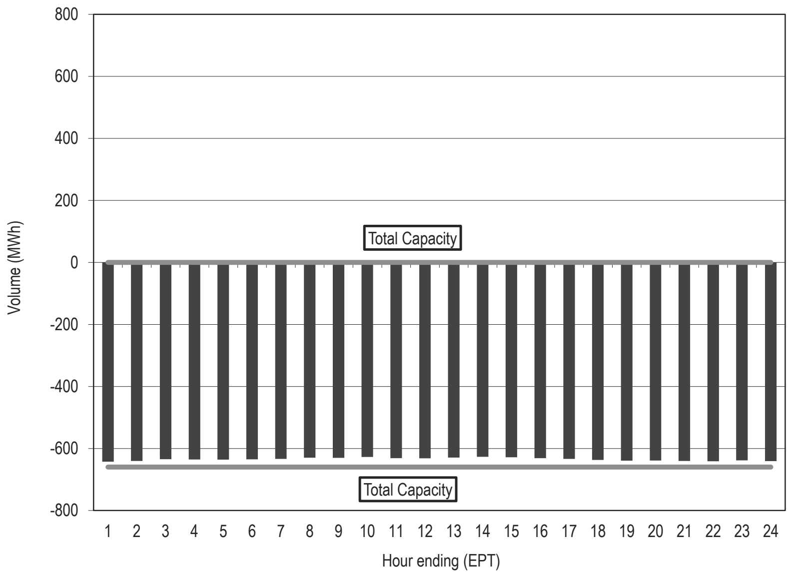
Table 9-32 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July 2007. Table 9-32 shows that in the first nine months of 2025, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in January through May, and in July through September and the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Neptune Line in June. Figure 9-7 shows the hourly average flow across the Neptune Line for the first nine months of 2025.

Table 9-32 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through September 2025

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.41%
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

27 See OASIS “PJM Business Practices for Neptune Transmission Service,” (August 21, 2015) <https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/neptune-oasis-business-practices-doc-clean.pdf>.
28 See OASIS “Regional Transmission and Energy Scheduling Practices,” Rev. 12 (July 26, 2023) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

Figure 9-7 Neptune hourly average flow: January through September, 2025



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 315 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 80.3 percent of the hours in the first nine months of 2025. Table 9-33 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden Bus based on LMP differences and flow direction.

Table 9-33 PJM and NYISO flow based hours and price differences (Linden): January through September, 2025

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	5,376	$26.86
	Consistent Flow (PJM to NYIS)	5,260	$26.92
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	116	$24.05
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	1,175	$40.31
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,166	$40.56
	No Flow	9	$7.82

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[29] The PJM Out Service is covered by normal PJM OASIS business operations.[30] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 1200 (EPT), one business day before the start of service. On September 30, 2025, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

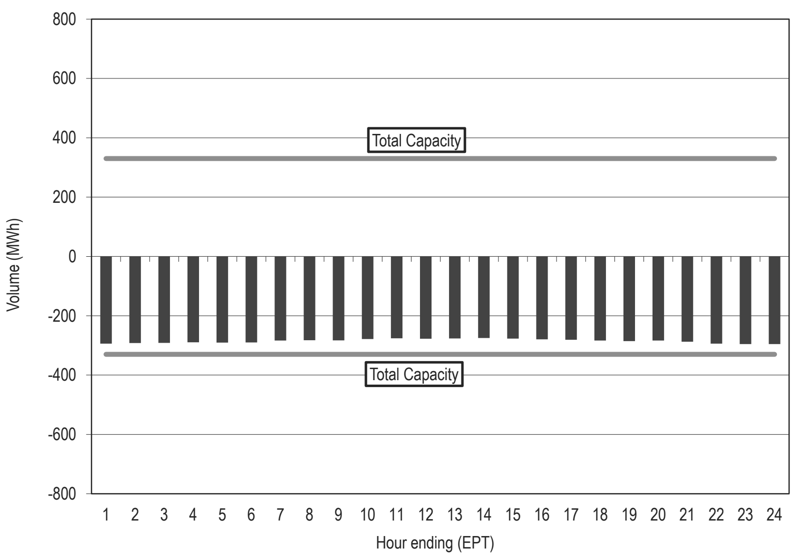
29 See OASIS "PJM Business Practices for Linden VFT Transmission Service," (June 1, 2011) <https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/linden-vft-oasis-business-practices-clean.pdf>.
30 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 12 (July 26, 2023) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

Table 9-34 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-34 shows that in the first nine months of 2025, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-8 shows the hourly average flow across the Linden VFT Line for the first nine months of 2025.

Table 9-34 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through September 2025

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	27.27%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Figure 9-8 Linden hourly average flow: January through September, 2025[31]



31 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (Con Ed) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC Line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC had only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of nonfirm withdrawal rights). The flows were consistent with price differentials in 80.7 percent of the hours in the first nine months of 2025. Table 9-35 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-35 PJM and NYISO flow based hours and price differences (Hudson): January through September, 2025

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	5,490	$28.69
	Consistent Flow (PJM to NYIS)	5,289	$29.18
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	201	$15.89
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	1,061	$22.32
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,002	$23.09
	No Flow	59	$9.22

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line ("Out Service") and another transmission service reservation is required on the Hudson Line ("Hudson Service").[32] The PJM Out Service is covered by normal PJM OASIS business operations.[33] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 1200 (EPT), one business day before the start of service. On September 30, 2025, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

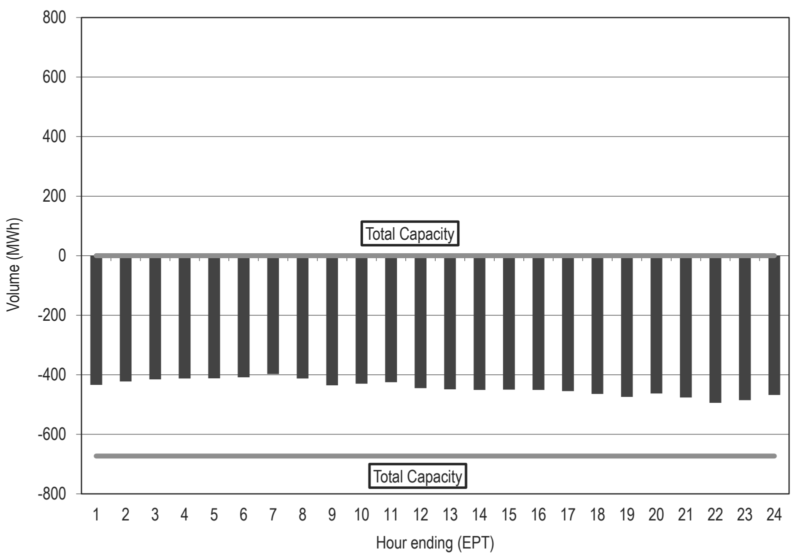
32 See OASIS "PJM Business Practices for Hudson Transmission Service,"<https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/hudson-oasis-business-practices-clean.pdf>.
33 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 12 (July 26, 2023) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

Table 9-36 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-36 shows that in the first nine months of 2025, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Hudson Line in all months. Figure 9-9 shows the hourly average flow across the Hudson Line for the first nine months of 2025.

Table 9-36 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through September 2025[34]

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%	29.70%	37.64%	64.30%	81.40%	100.00%	100.00%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%	23.61%	47.37%	64.34%	82.72%	100.00%	100.00%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.42%	87.24%	53.27%	82.65%	83.41%	100.00%	100.00%
April	NA	100.00%	100.00%	NA	NA	15.13%	100.00%	10.02%	70.90%	84.91%	100.00%	100.00%	100.00%
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	100.00%	20.53%	65.15%	84.15%	100.00%	100.00%	100.00%
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	44.98%	38.26%	73.81%	100.00%	100.00%	100.00%	100.00%
July	100.00%	18.51%	84.34%	NA	NA	16.26%	36.43%	27.56%	76.56%	100.00%	89.66%	100.00%	100.00%
August	100.00%	75.17%	65.48%	NA	NA	19.24%	43.10%	35.64%	59.09%	100.00%	100.00%	80.35%	100.00%
September	100.00%	75.31%	78.73%	NA	NA	22.90%	43.42%	30.75%	53.66%	100.00%	100.00%	100.00%	100.00%
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	33.60%	52.58%	56.26%	100.00%	100.00%	100.00%	
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	44.36%	38.60%	65.24%	68.68%	70.50%	100.00%	
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	41.78%	38.82%	61.11%	70.02%	83.43%	100.00%	

Figure 9-9 Hudson hourly average flow: January through September, 2025



34 The designation of "NA" means there was no flow on the Hudson Line during those months.

Interchange Activity During High Load Hours

The PJM metered system peak load during the first nine months of 2025 was 156,256 MW in the HE 1700 (EPT) on June 23, 2025. PJM was a net scheduled exporter of energy in all 24 hours on June 23, 2025, with average hourly scheduled exports of 3,360 MW. During HE 1700 on June 23, 2025, PJM had net scheduled exports of 2,296 MW and net metered actual exports of 2,158 MW. Net transaction exports during 1700 were consistent with price differences between the PJM/NEPT Interface and the NYIS/Neptune bus, the PJM/LIND Interface and the NYIS/Linden Bus and the PJM/HUDS Interface and the NYIS/Hudson Bus. Net transaction exports were inconsistent with price differences between PJM and MISO. Net transaction imports were consistent with price differences between PJM and the NYISO. During June 2025, PJM was a net scheduled exporter of energy in 718 of the 720 hours (99.7 percent of the hours). During June 2025, the average hourly scheduled interchange was -5,003 MW (representing 5.0 percent of the average hourly load of 99,752 MW in June 2025).

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements, including: operating agreements with MISO and the NYISO; a reliability agreement with TVA, LG&E and KU; an operating agreement with Duke Energy Progress, Inc.; a reliability coordination agreement with VACAR South; a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC); and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-37 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-37 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA-LGE-KU	PJM-DEP	PJM-VACAR	PJM-WEP	Northeastern Protocol
Data Exhange							
Real-Time Data	YES	YES	YES	YES	YES	YES	NO
Projected Data	YES	YES	YES	YES	NO	NO	NO
SCADA Data	YES	YES	YES	YES	NO	NO	NO
EMS Models	YES	YES	YES	YES	NO	NO	YES
Operations Planning Data	YES	YES	YES	YES	NO	NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO	NO	YES
Near-Term System Coordination							
Operating Limit Violation Assistance	YES	YES	YES	YES	YES	NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES	NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES	NO	NO
Outage Coordination	YES	YES	YES	YES	YES	NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO	NO	YES
Congestion Management Process							
ATC Coordination	YES	YES	YES	YES	NO	NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO	NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO	NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	NO	NO	NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO	YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement
PJM-NYISO = New York ISO/PJM Joint Operating Agreement
PJM-TVA-LGE-KU = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA), Louisville Gas and Electric Company (LGE) and Kentucky Utilities Company (KU)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[35]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for congestion management that, for designated flowgates within MISO and PJM, allows for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management. This process was designed to address the impacts of market flows which are the loop flows on MISO's system created by PJM generators serving PJM load and vice versa. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[36]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP. Prior to June

35 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.
36 See "PJM/MISO Joint and Common Market Initiative," <https://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common>.

1, 2017, MISO used all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[37] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Coordinated flowgates are identified to determine which flowgates the market flows from PJM or MISO affect significantly. This set of flowgates may then be used in the congestion management process. PJM and MISO will conduct sensitivity studies to determine which flowgates are significantly affected by the market flows of the operating entity's control zones (historic control areas that existed in the IDC). There are five studies to determine which flowgates the operating entity will monitor and help control. These studies include generation to load distribution factor studies, transfer distribution factor analysis and an external asynchronous resource study. PJM or MISO may also specify additional flowgates that have not passed any of the five studies to be coordinated flowgates where the operating entity expects to use the TLR process to manage congestion. A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.[38]

As of January 1, 2025, PJM had 208 flowgates eligible for M2M (Market to Market) coordination. In the first nine months of 2025, PJM added 16 flowgates and deleted 93 flowgates, resulting in 131 flowgates eligible for M2M coordination as of September 30, 2025. As of January 1, 2025, MISO had 222 flowgates eligible for M2M coordination. In the first nine months of 2025, MISO added 30 flowgates and deleted 62 flowgates, resulting in 190 flowgates eligible for M2M coordination as of September 30, 2025.

The firm flow entitlement (FFE) represents the amount of historic 2004 market flows that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the nonmonitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the nonmonitoring RTO will pay the monitoring RTO the difference between their market flow and their FFE times the monitoring RTO's shadow price of the RCF. The shadow price is the incremental cost of dispatching marginal generation resources to relieve congestion on the RCF. If the nonmonitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the nonmonitoring RTO. This payment is the difference between the nonmonitoring RTO's market flow and their FFE times the monitoring RTO's shadow price of the RCF.

April 1, 2004, known as the freeze date, is used to determine the firm rights on flowgates based on historic firm market flows that occurred prior to the implementation of M2M coordination. In the 21 years since 2004, significant topology and market changes have occurred, making the 2004 market flows irrelevant in 2025. The RTOs and stakeholders recognize that a modification to the definition of firm rights on flowgates is necessary. PJM and MISO stakeholders have spent years on the freeze date issues. No resolution to these issues appears imminent. The status quo results in significant payments by PJM customers to MISO customers. The final resolution should account for the investments made by each RTO in the transmission system. The final resolution should reflect current interchange patterns. In 2004, PJM was primarily an importer of energy from MISO. In 2025, as it has been since about 2010, PJM is primarily an exporter of energy to MISO.

The MMU recommends eliminating the mechanism that defines FFE and M2M payments. These mechanisms are not consistent with markets and are not needed for efficient interface pricing. PJM and MISO have demonstrated a longstanding failure to resolve the definition of firm rights on flowgates and related issues. The MMU recommends that PJM file with the Commission to eliminate the FFE calculation and M2M payment of the PJM and MISO joint operating agreement.

The original logic of FFEs was not clear, the calculation of FFEs was not clear, and the measurement of market flows was and is imprecise at best. It does not

37 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.
38 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

make sense to use outdated and meaningless FFEs from 2004. If current FFEs are used based on actual current power flows, the role of FFEs is not clear. Fully dynamic FFEs are equivalent to eliminating FFEs while continuing to price power flows at the correct shadow price.

The solution to the FFE and M2M issue is to eliminate FFEs. Elimination of FFEs, while maintaining the exchange of shadow price information and cooperative dispatch, would keep the benefits of efficient constraint resolution between PJM and MISO.

In the first nine months of 2025, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Table 9-38 shows credits for coordinated congestion management between PJM and MISO. In the first nine months of 2025, MISO payments to PJM were $7.6 million, and PJM payments to MISO were $63.8 million, for a net payment from PJM to MISO of $56.2 million. The large settlements in 2022 were due to the large amount of congestion and high LMPs observed in December during Winter Storm Elliott.

Table 9-38 PJM/MISO credits for coordinated congestion management: April 2005 through September 2025[39]

Year	Payments from PJM to MISO	Payments from MISO to PJM	Net Payment from PJM to MISO
2005	$25,068,903	$3,411,188	$21,657,715
2006	$18,664,630	$21,381,460	($2,716,830)
2007	$29,917,241	$17,774,637	$12,142,604
2008	$60,615,478	$15,417,040	$45,198,438
2009	$48,101,017	$10,632,885	$37,468,132
2010	$56,330,068	$20,558,982	$35,771,087
2011	$87,113,498	$9,445,949	$77,667,550
2012	$56,227,681	$7,602,112	$48,625,569
2013	$32,589,519	$14,733,770	$17,855,748
2014	$62,572,610	$19,263,896	$43,308,713
2015	$49,379,823	$11,266,866	$38,112,957
2016	$50,628,816	$9,826,347	$40,802,469
2017	$69,812,858	$16,698,276	$53,114,581
2018	$110,501,078	$10,400,122	$100,100,956
2019	$44,391,547	$7,886,392	$36,505,155
2020	$53,038,595	$7,985,027	$45,053,568
2021	$45,704,128	$18,792,183	$26,911,945
2022	$191,716,652	$8,560,992	$183,155,660
2023	$63,976,499	$5,467,435	$58,509,064
2024	$58,627,460	$17,671,566	$40,955,894
2025 (Jan)	$16,303,017	$0	$16,303,017
2025 (Feb)	$7,040,650	$272,322	$6,768,328
2025 (Mar)	$11,328,210	$149,429	$11,178,782
2025 (Apr)	$12,140,633	$385,758	$11,754,874
2025 (May)	$4,122,837	$69,789	$4,053,049
2025 (Jun)	$3,117,356	$2,614,125	$503,231
2025 (Jul)	$2,314,333	$1,332,336	$981,997
2025 (Aug)	$1,036,764	$2,428,997	($1,392,233)
2025 (Sep)	$6,406,708	$369,613	$6,037,094
2025	$63,810,508	$7,622,368	$56,188,140

39 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[40]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. Unlike the PJM/MISO JOA where firm flow entitlements are based on a freeze date, the PJM/NYISO JOA requires that each party calculates an M2M entitlement on each M2M flowgate and compare results at least once a year. This annual coordination of entitlements ensures that the impact of upgrades on both systems are incorporated into the M2M calculation. PJM and NYISO may mutually agree to not recalculate entitlements in a given year.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions addressed RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch is to mitigate post-contingency overloads of transmission equipment on the New York side of the East Towanda-Hillside 230 kV Transmission Line. The agreement allows the RTOs to control for this contingency without the exchange of payments for redispatch.[41]

In the first nine months of 2025, market to market operations did not result in NYISO and PJM redispatching units to control congestion on M2M flowgates. Therefore, there was no exchange of payments for redispatch in the first nine months of 2025. Table 9-39 shows credits for coordinated congestion management between PJM and NYISO.

40 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <https://www.pjm.com/~/media/DotCom/documents/agreements/nyiso-joa.ashx>.
41 See NYISO Filing, FERC Docket No. ER19-2282-000 (June 28, 2019).

Table 9-39 PJM/NYISO credits for coordinated congestion management (flowgates): January 2013 through September 2025[42]

Year	Payments from PJM to NYISO	Payments from NYISO to PJM	Net Payment from PJM to NYISO
2013	$119,121	$0	$119,121
2014	$58,631	$1,005	$57,626
2015	$242,488	$5,063	$237,425
2016	$632,768	$50,550	$582,219
2017	$422,304	$895	$421,409
2018	$0	$0	$0
2019	$0	$0	$0
2020	$0	$0	$0
2021	$0	$0	$0
2022	$0	$0	$0
2023	$0	$0	$0
2024	$0	$0	$0
2025 (Jan)	$0	$0	$0
2025 (Feb)	$0	$0	$0
2025 (Mar)	$0	$0	$0
2025 (Apr)	$0	$0	$0
2025 (May)	$0	$0	$0
2025 (Jun)	$0	$0	$0
2025 (Jul)	$0	$0	$0
2025 (Aug)	$0	$0	$0
2025 (Sep)	$0	$0	$0
2025	$0	$0	$0

The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located at the PJM/NYIS border. This real-time coordination results in an efficient economic dispatch solution across both markets to manage the real-time transmission constraints that affect both markets, focusing on the actual flows in real time to manage constraints.[43] For each M2M flowgate, a PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM.

42 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
43 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <https://www.pjm.com/~/media/DotCom/documents/agreements/nyiso-joa.ashx>.

This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In the first nine months of 2025, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. In the first nine months of 2025, PJM payments to NYISO were $2.6 million, and NYISO payments to PJM were $3.2 million, for a net payment from NYISO to PJM of $565,570. Table 9-40 shows the PAR credits for coordinated congestion management between PJM and NYISO.

Table 9-40 PJM/NYISO credits for coordinated congestion management (PARs): January 2013 through September 2025[44]

Year	Payments from PJM to NYISO	Payments from NYISO to PJM	Net Payment from PJM to NYISO
2013	$7,403,255	$0	$7,403,255
2014	$5,723,571	$0	$5,723,571
2015	$4,691,302	$0	$4,691,302
2016	$617,733	$0	$617,733
2017	$2,328,763	$2,115,126	$213,637
2018	$3,327,747	$2,407,667	$920,081
2019	$3,341,615	$2,923,715	$417,900
2020	$3,004,543	$2,048,317	$956,226
2021	$8,911,160	$6,751,890	$2,159,270
2022	$21,128,605	$13,611,434	$7,517,171
2023	$1,755,207	$2,208,388	($453,181)
2024	$376,435	$1,227,033	($850,597)
2025 (Jan)	$1,057,106	$1,751,095	($693,989)
2025 (Feb)	$193,284	$427,199	($233,915)
2025 (Mar)	$178,336	$339,994	($161,657)
2025 (Apr)	$2,290	$1,203	$1,087
2025 (May)	$3,690	$985	$2,705
2025 (Jun)	$656,570	$344,867	$311,702
2025 (Jul)	$543,293	$149,277	$394,016
2025 (Aug)	$12,092	$148,239	($136,148)
2025 (Sep)	$28,036	$77,407	($49,371)
2025	$2,674,697	$3,240,267	($565,570)

44 The totals in this figure are from the settlements at the time of this report and may change based on later adjustments or resettlements.

PJM and TVA/LG&E and KU Joint Reliability Coordination Agreement (JRCA)[45]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. In 2022, PJM and TVA began discussions to add Louisville Gas and Electric Company (LG&E) and Kentucky Utilities (KU) as parties to the JRCA. The revisions to add LG&E and KU to the agreement were filed with the Commission on June 6, 2023.[46] On August 5, 2023, the Commission approved the filing.[47] The agreement remained in effect in the first nine months of 2025.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[48]

On September 9, 2005, FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to include a CMP under Article 14 of the JOA.[49] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy

45 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <https://www.pjm.com/library/governing-documents>.
46 See *PJM Interconnection, L.L.C*, Docket No. ER23-2078-000 (June 6, 2023).
47 See *PJM Interconnection, L.L.C*, Docket No. ER23-2078-000 (August 5, 2023).
48 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (July 22, 2019) <https://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.
49 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

Carolinas Inc., now a subsidiary of Duke Energy, changed its name to Duke Energy Progress (DEP).

On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.[50] PJM and DEP requested an effective date of July 22, 2019, for the filed revisions. On July 2, 2019, the Commission issued a letter order accepting the revisions to the JOA to delete the congestion management agreement effective July 22, 2019.[51]

PJM and VACAR South Reliability Coordination Agreement[52]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (part of Alcoa)) entered into a reliability coordination agreement which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in the first nine months of 2025.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[53]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in the first nine months of 2025.

50 See *PJM Interconnection, L.L.C*, Docket No. ER19-1905-000 (May 20, 2019).
51 FERC Docket No. ER19-1905-000.
52 See "PJM-VACAR South RC Agreement," (November 7, 2014) <https://www.pjm.com/-/media/DotCom/documents/agreements/executed-pjm-vacar-rc-agreement.pdf>.
53 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C.," (July 20, 2013) <https://www.pjm.com/directory/merged-tariffs/rs43.pdf>.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[54]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in the first nine months of 2025.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, loop flows for example, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher increased from zero in the first nine months of 2024 to two in the first nine months of 2025. The number of different flowgates for which PJM declared a TLR 3a was zero in the first nine months of 2024, and two in the first nine months of 2025. The total MWh of transaction curtailments was zero in the first nine months of 2024, and 5,646 MWh in the first nine months of 2025.[55]

The number of MISO issued TLRs of level 3a or higher increased from 17 in the first nine months of 2024 to 22 in the first nine months of 2025. The number of different flowgates for which MISO declared a TLR 3a was 13 in the first nine months of 2024, and 12 in the first nine months of 2025. The total MWh of transaction curtailments decreased by 4.5 percent from 13,048 MWh in the first nine months of 2024 to 12,462 MWh in the first nine months of 2025.

54 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <https://www.pjm.com/-/media/DotCom/documents/agreements/NE_Protocol.ashx>.
55 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2020 Annual State of the Market Report for PJM*, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

The number of NYISO issued TLRs of level 3a or higher decreased from two in the first nine months of 2024 to zero in the first nine months of 2025. The number of different flowgates for which NYISO declared a TLR 3a or higher was one in the first nine months of 2024, and zero in the first nine months of 2025. The total MWh of transaction curtailments was from 11,597 MWh in the first nine months of 2024, and zero MWh in the first nine months of 2025.

Table 9-41 PJM, MISO, and NYISO TLR procedures: January through September, 2025[56]

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-25	2	2	0	2	2	0	5,646	5,266	0
Feb-25	0	0	0	0	0	0	0	0	0
Mar-25	0	1	0	0	1	0	0	120	0
Apr-25	0	6	0	0	2	0	0	5,568	0
May-25	0	3	0	0	2	0	0	421	0
Jun-25	0	0	0	0	0	0	0	0	0
Jul-25	0	2	0	0	2	0	0	0	0
Aug-25	0	2	0	0	1	0	0	175	0
Sep-25	0	6	0	0	4	0	0	912	0
Total	2	22	0	2	12	0	5,646	12,462	0

Table 9-42 Number of TLRs by TLR level by reliability coordinator: January through September, 2025[57]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2025	MISO	9	3	0	3	7	0	22
	NYIS	0	0	0	0	0	0	0
	ONT	1	0	0	0	0	0	1
	PJM	0	2	0	0	0	0	2
	SOCO	58	89	0	0	0	0	147
	SWPP	84	136	0	10	14	0	244
	TVA	31	26	0	5	5	0	67
	VACS	2	8	0	0	0	0	10
Total		185	264	0	18	26	0	493

56 The total row in the columns of the number of unique flowgates that experience TLRs are not a sum of the individual months. The total row represents the number of unique flowgates that have experienced TLRs for the year to date.
57 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.

Up To Congestion Transactions

The original purpose, in 2000, of up to congestion transactions (UTC) was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the day-ahead energy market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the real-time energy market.[58]

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions were not required to pay uplift charges from their introduction in 2000 through October 31, 2020. On July 16, 2020, FERC issued an Order directing PJM to revise uplift allocation rules to allocate uplift to one side of up to congestion transactions.[59] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. Up to congestion transactions also negatively affect FTR funding.[60]

Figure 9-10 shows the monthly volume of cleared up to congestion transactions. Following an initial decline, UTC volumes had steadily increased following the allocation of uplift charges to UTCs effective November 1, 2020. However, the volume of cleared UTC transactions has declined again in the recent 12 month period to levels below what was seen prior to the allocation of uplift charges to UTCs. Table 9-43 shows the UTC volumes from the 12 month period prior to the allocation of uplift charges (November 1, 2019, through October 31, 2020), to the most recent 12 month period (October 1, 2024 through September 30, 2025). Table 9-44 shows the UTC volumes for the first nine months of 2024 and 2025.

58 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.
59 172 FERC ¶ 61,046 (2020).
60 See the *2025 Quarterly State of the Market Report for PJM: January through September*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

Figure 9-10 Monthly up to congestion cleared bids in MWh: January 2005 through September 2025

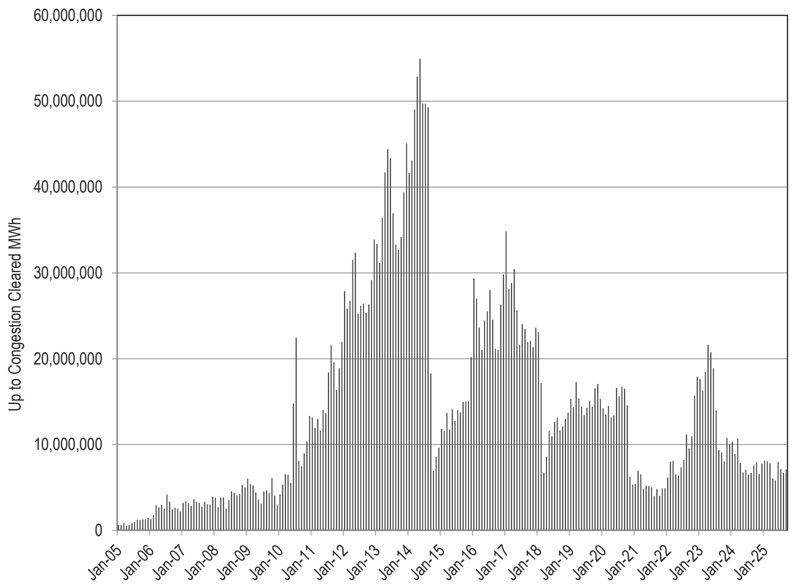


Table 9-43 Up to congestion volumes: November 1, 2019 through October 31, 2020 compared to October 1, 2024 through September 30, 2025

Category	November 1, 2019 - October 31, 2020	October 1, 2024 - September 30, 2025	Percent Change
Daily Average UTC Bids Submitted	53,368	46,408	(13.0%)
Daily Average UTC Bids Cleared	26,415	17,251	(34.7%)
Daily Average UTC Volume Submitted (MWh)	1,279,124	744,973	(41.8%)
Daily Average UTC Volume Cleared (MWh)	495,001	238,600	(51.8%)

Table 9-44 Up to congestion volumes: January through September, 2024 and 2025

Category	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change
Daily Average UTC Bids Submitted	36,083	48,979	35.7%
Daily Average UTC Bids Cleared	16,374	17,795	8.7%
Daily Average UTC Volume Submitted (MWh)	747,595	737,144	(1.4%)
Daily Average UTC Volume Cleared (MWh)	264,091	237,417	(10.1%)

Table 9-45 shows the monthly cleared submitted volume of UTC bids from January 2024 through September 2025. In the first nine months of 2025, the cleared MW volume of up to congestion transactions was comprised of 7.6 percent imports, 5.8 percent exports, 1.6 percent wheeling transactions and 85.0 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Table 9-45 Monthly volume of cleared and submitted up to congestion bids: January 2024 through September, 2025

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-24	1,393,908	3,446,217	622,629	20,738,830	26,201,585	109,639	177,019	28,013	925,575	1,240,246
Feb-24	1,276,448	3,487,721	557,922	15,563,296	20,885,387	85,438	162,871	19,625	641,688	909,622
Mar-24	2,114,589	3,095,560	615,033	22,158,786	27,983,969	104,029	137,178	15,664	806,929	1,063,800
Apr-24	2,553,802	880,919	631,655	21,263,080	25,329,456	132,464	57,815	12,169	836,727	1,039,175
May-24	1,770,205	1,086,810	351,244	19,034,294	22,242,552	112,625	64,120	11,640	977,182	1,165,567
Jun-24	1,623,412	1,186,571	207,398	15,883,613	18,900,994	82,777	64,774	8,241	826,865	982,657
Jul-24	1,382,861	1,410,922	228,738	17,081,886	20,104,409	88,958	74,617	8,613	967,827	1,140,015
Aug-24	1,745,713	1,889,045	395,980	16,778,581	20,809,318	113,673	84,362	11,550	962,180	1,171,765
Sep-24	1,919,983	2,052,034	378,662	18,032,721	22,383,400	108,782	95,667	13,048	956,495	1,173,992
Oct-24	2,506,298	1,888,422	299,715	20,096,647	24,791,083	131,812	96,221	11,494	959,073	1,198,600
Nov-24	1,630,883	1,941,307	369,918	17,782,010	21,724,119	96,476	102,770	12,427	825,449	1,037,122
Dec-24	2,915,183	2,366,307	412,163	18,466,015	24,159,668	159,107	140,388	18,745	1,013,390	1,331,630
Jan-25	2,205,672	2,182,123	334,327	21,101,450	25,823,572	125,604	187,964	18,092	1,300,404	1,632,064
Feb-25	2,455,996	2,513,637	359,618	18,056,777	23,386,028	114,520	183,212	32,050	1,036,986	1,366,768
Mar-25	3,118,908	1,826,595	278,735	20,664,128	25,888,366	170,467	150,970	20,393	1,214,563	1,556,393
Apr-25	2,179,369	789,354	341,206	17,872,615	21,182,544	169,667	95,947	17,035	1,156,357	1,439,006
May-25	1,300,945	867,919	224,558	13,954,428	16,347,850	105,869	85,547	12,625	966,859	1,170,900
Jun-25	1,814,662	1,402,459	171,331	19,928,093	23,316,546	144,615	104,586	12,351	1,229,721	1,491,273
Jul-25	2,271,084	1,445,784	259,642	17,998,508	21,975,019	186,792	125,712	18,569	1,327,626	1,658,699
Aug-25	2,006,277	1,591,872	280,230	15,399,345	19,277,724	146,474	122,446	18,102	1,053,784	1,340,806
Sep-25	1,417,219	2,117,739	234,451	20,273,139	24,042,548	154,729	134,822	15,782	1,410,148	1,715,481
TOTAL	41,603,415	39,469,320	7,555,158	388,128,243	476,756,136	2,644,517	2,449,008	336,228	21,395,828	26,825,581

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-24	432,931	1,174,081	249,337	8,489,035	10,345,385	50,907	74,004	11,400	448,898	585,209
Feb-24	490,568	986,528	245,479	7,167,365	8,889,940	34,100	54,648	6,789	296,101	391,638
Mar-24	688,499	964,650	274,492	8,772,338	10,699,978	37,226	54,211	5,702	348,530	445,669
Apr-24	575,102	319,891	253,730	6,714,925	7,863,648	37,781	23,217	4,342	320,186	385,526
May-24	391,409	375,117	168,607	5,815,471	6,750,604	36,393	27,920	3,660	398,792	466,765
Jun-24	488,592	476,316	71,640	6,026,374	7,062,923	35,413	30,970	3,012	390,313	459,708
Jul-24	352,243	455,325	79,374	5,601,800	6,488,742	37,627	30,095	1,938	493,552	563,212
Aug-24	563,725	410,942	143,077	5,590,248	6,707,992	56,263	24,647	4,618	540,450	625,978
Sep-24	634,070	507,312	139,039	6,271,395	7,551,817	41,991	31,418	5,009	484,376	562,794
Oct-24	734,933	526,973	96,888	6,589,942	7,948,736	43,705	33,318	3,706	417,490	498,219
Nov-24	418,179	528,677	152,846	5,456,604	6,556,306	33,395	31,180	4,160	315,374	384,109
Dec-24	945,870	509,356	178,429	6,135,454	7,769,108	69,597	43,388	8,311	435,152	556,448
Jan-25	464,114	701,211	108,021	6,876,908	8,150,254	32,413	91,771	6,004	547,475	677,663
Feb-25	748,465	537,412	144,845	6,633,542	8,064,264	41,822	54,750	11,534	428,231	536,337
Mar-25	678,923	587,700	152,636	6,391,031	7,810,290	46,728	57,345	7,116	439,419	550,608
Apr-25	397,841	217,089	149,400	5,294,497	6,058,826	35,760	26,334	4,065	373,011	439,170
May-25	363,478	312,867	120,464	5,044,292	5,841,101	24,841	20,884	3,267	324,995	373,987
Jun-25	590,128	292,998	81,725	6,988,373	7,953,223	56,190	26,403	3,754	483,442	569,789
Jul-25	678,823	266,906	74,374	6,118,292	7,138,395	79,167	25,831	5,399	568,717	679,114
Aug-25	702,076	328,270	99,923	5,580,230	6,710,499	55,827	27,995	5,273	408,458	497,553
Sep-25	328,860	509,245	75,506	6,174,356	7,087,967	39,739	30,513	3,961	459,532	533,745
TOTAL	11,668,827	10,988,867	3,059,833	133,732,471	159,449,997	926,885	820,842	113,020	8,922,494	10,783,241

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority cannot see how the power will flow to the load, which can create loop flows and result in inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM energy market, at the PJM/NYIS Interface regardless of the submitted path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

At the April 10, 2013, PJM Market Implementation Committee (MIC), the MMU presented a problem statement and issue charge to address sham scheduling activities.[61] The expected deliverables from the stakeholder meetings were revisions to the Tariff and PJM business manuals. The topic was discussed at several MIC meetings. While there was stakeholder agreement that sham scheduling activity was inappropriate, consensus on revised tariff and manual language was not achieved. The topic was closed. The MMU clarified that it would continue to monitor transactions for sham scheduling activities and that the MMU could refer market participants for sham scheduling activities.

The MMU monitors for sham scheduling activities on a daily basis. Following the stakeholder discussions in 2013, the net profits obtained from sham scheduling activities fell by 104.9 percent, from net profits of $15.5 million in 2014, to a net loss of $761,012 in 2024. The total number of hours of sham scheduling segments where the MW profile matched exactly across all segments of the path combinations in the same hour fell by 86.6 percent, from 1,898 hours in 2014 to 254 hours in 2024.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/IMO interface pricing point to reflect the

61 *See* Market Path/Interface Pricing Point alignment Problem Statement, at: <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Market_Path_Interface_Pricing_Point_Alignment_Problem_Statement_201304010.pdf>.

actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities.[62] For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market. This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO Interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS Interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In the first nine months of 2025, there were 666.5 GWh of net scheduled transactions between PJM and IESO. The net scheduled transactions were made up of 676.5 GWh of imports wheeled through MISO, and 10.0 GWh of exports wheeled through the NYISO. (Table 9-25). The MMU recommends

62 *See* "Sham Scheduling," Presented at the PJM Market Monitoring Unit Advisory Committee (MMUAC) meeting held on December 6, 2013 <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_Sham_Scheduling_20131206.pdf>.

that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[63]

PJM and NYISO Coordinated Interchange Transactions

Coordinated transaction scheduling (CTS) provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated.[64] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price IT SCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first nine months of 2025. Table 9-46 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 22.5 percent of the intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.22 per MWh. In 26.3 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $94.53 when the price difference was greater than $20.00, and $67.32 when the price difference was greater than -$20.00.

63 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.
64 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

Table 9-46 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2025

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	18.4%	$94.53
$10 to $20	10.3%	$14.29
$5 to $10	11.3%	$7.22
$0 to $5	22.5%	$2.22
$0 to -$5	17.4%	$2.04
-$5 to -$10	6.4%	$7.18
-$10 to -$20	5.7%	$14.33
< -$20	7.9%	$67.32

Table 9-47 shows how the accuracy of the IT SCED forecasted LMPs changes as the cases approach real-time. In the final IT SCED results prior to real time, in 35.5 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 39.5 percent in the 135 minute ahead IT SCED results.

Table 9-47 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2025

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	23.2%	$99.14	15.6%	$77.12	17.8%	$90.62	20.1%	$106.99
$10 to $20	10.6%	$14.39	10.4%	$14.25	9.9%	$14.23	10.2%	$14.36
$5 to $10	11.1%	$7.24	11.5%	$7.23	11.5%	$7.21	10.2%	$7.26
$0 to $5	23.2%	$2.18	24.4%	$2.21	21.6%	$2.25	17.9%	$2.24
$0 to -$5	16.3%	$1.91	18.1%	$2.01	17.4%	$2.09	17.6%	$2.21
-$5 to -$10	5.1%	$7.08	6.3%	$7.23	6.9%	$7.14	7.7%	$7.16
-$10 to -$20	4.4%	$14.47	5.6%	$14.37	6.3%	$14.27	6.9%	$14.25
< -$20	6.1%	$70.36	8.0%	$66.57	8.6%	$68.01	9.4%	$64.41

In 29.5 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price difference was $106.99 when the price difference was greater than $20.00, and $64.41 when the price difference was greater than -$20.00.

Table 9-48 and Table 9-49 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-48 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January through September, 2025

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
	> $20	19.1%	24.6%	18.8%	21.8%	14.2%	20.2%	32.8%	15.6%	13.8%	20.1%
	$10 to $20	9.2%	8.4%	9.7%	14.7%	10.2%	9.5%	9.3%	9.2%	12.0%	10.2%
	$5 to $10	11.1%	8.5%	12.4%	13.3%	11.1%	10.1%	5.8%	9.8%	9.2%	10.2%
~ 30 Minutes Prior to Real-Time	$0 to $5	17.2%	12.7%	18.7%	22.7%	25.7%	16.2%	13.3%	17.1%	17.4%	17.9%
	$0 to -$5	15.7%	13.2%	16.5%	14.5%	24.6%	16.4%	14.7%	23.0%	19.2%	17.6%
	-$5 to -$10	6.7%	7.8%	7.6%	4.7%	7.3%	8.3%	7.6%	9.6%	9.6%	7.7%
	-$10 to -$20	7.6%	9.1%	7.4%	3.7%	3.4%	7.9%	6.8%	8.1%	8.7%	6.9%
	< -$20	13.4%	15.9%	9.0%	4.7%	3.5%	11.3%	9.8%	7.5%	10.1%	9.4%

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
	> $20	19.1%	25.0%	17.9%	23.4%	10.6%	17.5%	26.1%	11.5%	10.3%	17.8%
	$10 to $20	10.4%	8.6%	9.7%	12.0%	9.6%	10.2%	10.6%	8.9%	9.3%	9.9%
	$5 to $10	12.0%	9.4%	12.6%	14.6%	12.7%	11.5%	7.9%	11.4%	11.2%	11.5%
~ 45 Minutes Prior to Real-Time	$0 to $5	20.0%	14.5%	20.4%	24.0%	31.2%	20.4%	16.9%	23.5%	22.8%	21.6%
	$0 to -$5	14.6%	12.7%	16.3%	14.2%	23.6%	17.3%	15.9%	22.1%	19.5%	17.4%
	-$5 to -$10	6.6%	7.7%	7.5%	4.2%	5.9%	7.4%	6.6%	7.7%	8.8%	6.9%
	-$10 to -$20	6.7%	8.3%	7.1%	3.3%	3.1%	5.9%	6.8%	7.5%	7.9%	6.3%
	< -$20	10.6%	13.7%	8.6%	4.4%	3.5%	9.9%	9.2%	7.4%	10.2%	8.6%

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
	> $20	16.0%	21.3%	13.5%	15.4%	7.9%	17.4%	26.5%	11.8%	11.2%	15.6%
	$10 to $20	10.3%	10.1%	10.1%	11.1%	8.6%	11.5%	11.4%	10.1%	10.2%	10.4%
	$5 to $10	12.2%	9.1%	11.6%	13.9%	13.2%	11.2%	9.5%	11.2%	11.4%	11.5%
~ 90 Minutes Prior to Real-Time	$0 to $5	24.0%	16.2%	24.0%	28.3%	33.9%	22.5%	19.7%	24.9%	25.2%	24.4%
	$0 to -$5	15.1%	14.4%	17.4%	18.1%	24.3%	17.1%	15.0%	22.7%	18.7%	18.1%
	-$5 to -$10	5.9%	8.1%	8.1%	4.0%	5.4%	6.1%	4.8%	7.4%	7.4%	6.3%
	-$10 to -$20	5.5%	7.8%	6.4%	4.3%	3.3%	5.6%	4.9%	5.8%	7.2%	5.6%
	< -$20	11.0%	13.0%	8.9%	5.0%	3.3%	8.5%	8.1%	6.1%	8.6%	8.0%

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
	> $20	21.8%	30.0%	24.0%	21.0%	16.5%	22.1%	34.3%	18.5%	20.8%	23.2%
	$10 to $20	10.8%	7.8%	10.9%	11.4%	10.1%	11.3%	11.7%	10.2%	10.7%	10.6%
	$5 to $10	10.6%	9.0%	11.1%	12.4%	13.3%	11.1%	9.4%	11.4%	11.3%	11.1%
~ 135 Minutes Prior to Real-Time	$0 to $5	23.0%	14.5%	21.0%	27.9%	30.6%	23.8%	19.3%	25.1%	22.9%	23.2%
	$0 to -$5	14.5%	14.5%	16.3%	16.9%	20.9%	15.6%	11.8%	19.3%	16.6%	16.3%
	-$5 to -$10	5.2%	7.2%	6.0%	4.0%	3.8%	4.8%	3.5%	5.7%	5.9%	5.1%
	-$10 to -$20	5.0%	6.2%	4.2%	3.2%	2.6%	4.3%	4.2%	5.2%	5.3%	4.4%
	< -$20	9.1%	10.8%	6.5%	3.3%	2.3%	6.8%	5.8%	4.5%	6.6%	6.1%

Table 9-49 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through September, 2025

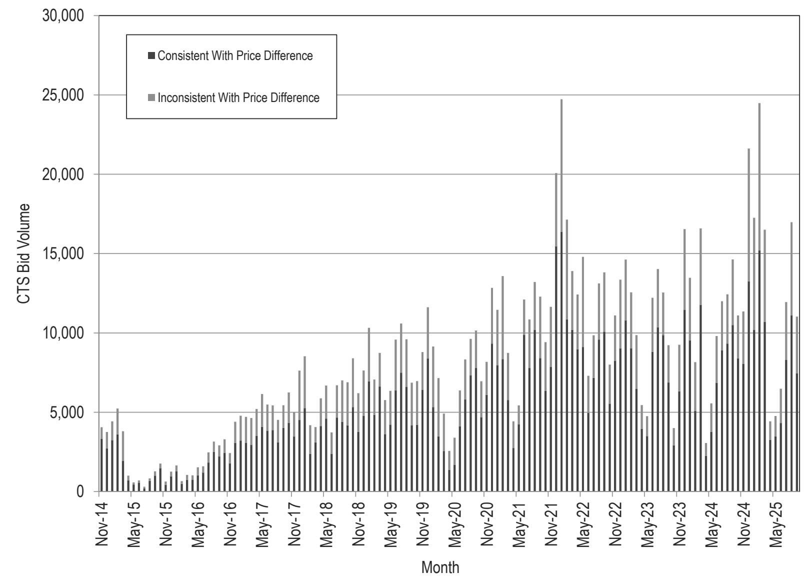
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$66.91	$73.56	$57.65	$47.28	$37.02	$257.61	$203.85	$72.90	$39.03	$106.99
	$10 to $20	$14.16	$14.45	$14.37	$14.30	$13.95	$14.48	$15.10	$14.13	$14.41	$14.36
	$5 to $10	$7.10	$7.50	$7.16	$7.32	$7.20	$7.28	$7.29	$7.13	$7.48	$7.26
	$0 to $5	$2.39	$2.29	$2.36	$2.30	$2.15	$2.21	$2.15	$2.03	$2.27	$2.24
	$0 to -$5	$2.16	$2.32	$2.29	$2.07	$2.14	$2.10	$2.37	$2.17	$2.33	$2.21
	-$5 to -$10	$7.13	$7.19	$7.14	$7.23	$6.94	$7.39	$7.27	$7.19	$7.03	$7.16
	-$10 to -$20	$14.22	$14.14	$14.40	$13.86	$14.05	$14.29	$14.37	$14.43	$14.19	$14.25
	< -$20	$66.18	$50.37	$71.55	$75.27	$68.96	$92.87	$51.02	$51.97	$60.65	$64.41
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$56.99	$73.95	$65.32	$55.25	$43.32	$205.16	$151.34	$66.71	$41.61	$90.62
	$10 to $20	$14.20	$14.46	$13.96	$14.11	$14.06	$14.40	$14.59	$14.11	$14.20	$14.23
	$5 to $10	$7.28	$7.25	$7.16	$7.20	$7.09	$7.24	$7.23	$7.19	$7.35	$7.21
	$0 to $5	$2.45	$2.36	$2.34	$2.30	$2.19	$2.30	$2.04	$2.12	$2.24	$2.25
	$0 to -$5	$2.20	$2.22	$2.22	$1.87	$2.00	$2.07	$2.18	$1.90	$2.23	$2.09
	-$5 to -$10	$7.18	$7.19	$7.18	$7.02	$7.13	$7.12	$7.22	$7.15	$7.02	$7.14
	-$10 to -$20	$14.23	$14.71	$14.48	$13.93	$14.15	$14.14	$14.15	$14.06	$14.28	$14.27
	< -$20	$69.97	$52.43	$71.80	$75.76	$69.31	$106.08	$57.08	$55.11	$61.32	$68.01
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$51.98	$54.21	$48.84	$43.51	$40.30	$169.07	$108.96	$74.13	$45.78	$77.12
	$10 to $20	$14.45	$14.10	$13.74	$14.52	$13.69	$14.44	$14.56	$14.36	$14.20	$14.25
	$5 to $10	$7.23	$7.40	$7.12	$7.19	$7.16	$7.30	$7.35	$7.14	$7.31	$7.23
	$0 to $5	$2.39	$2.33	$2.26	$2.20	$2.14	$2.16	$2.19	$2.09	$2.20	$2.21
	$0 to -$5	$2.12	$2.22	$2.06	$1.94	$1.93	$2.04	$2.01	$1.87	$2.10	$2.01
	-$5 to -$10	$7.06	$7.37	$7.21	$7.12	$7.06	$7.49	$7.12	$7.40	$7.13	$7.23
	-$10 to -$20	$14.32	$14.29	$14.53	$14.14	$14.45	$14.16	$14.75	$14.27	$14.42	$14.37
	< -$20	$71.43	$50.57	$72.52	$72.23	$70.10	$89.99	$56.46	$58.33	$64.48	$66.57
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$99.65	$102.31	$100.22	$81.31	$86.93	$155.81	$101.53	$83.00	$71.44	$99.14
	$10 to $20	$14.34	$14.32	$14.26	$14.37	$14.19	$14.54	$14.54	$14.25	$14.65	$14.39
	$5 to $10	$7.20	$7.27	$7.22	$7.12	$7.25	$7.33	$7.34	$7.31	$7.13	$7.24
	$0 to $5	$2.26	$2.22	$2.25	$2.15	$2.27	$2.07	$2.17	$1.98	$2.22	$2.18
	$0 to -$5	$1.88	$2.13	$2.05	$1.86	$1.73	$1.80	$1.97	$1.83	$2.06	$1.91
	-$5 to -$10	$7.11	$7.26	$7.13	$7.06	$7.00	$6.85	$7.08	$7.08	$7.09	$7.08
	-$10 to -$20	$14.39	$14.41	$14.17	$14.15	$14.17	$14.47	$14.84	$14.59	$14.77	$14.47
	< -$20	$68.63	$50.04	$76.38	$89.39	$79.96	$101.33	$60.50	$62.17	$67.38	$70.36

The NYISO uses PJM's IT SCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the IT SCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through September 30, 2025, 1,060,261 15 minute CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 330,293 (31.2 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 31.2 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 68.8 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-11 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-11 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-11 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through September 30, 2025



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO Interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/MISO interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first nine months of 2025. Table 9-50 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 23.2 percent of all intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.16. In 27.4 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $90.19 when the price difference was greater than $20.00, and $76.35 when the price difference was greater than -$20.00.

Table 9-50 Differences between forecast and actual PJM/MISO interface prices: January through September, 2025

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	22.3%	$90.19
$10 to $20	10.1%	$14.27
$5 to $10	10.9%	$7.22
$0 to $5	23.2%	$2.16
$0 to -$5	18.6%	$1.96
-$5 to -$10	5.7%	$7.09
-$10 to -$20	4.0%	$14.08
< -$20	5.1%	$76.35

Table 9-51 shows how the accuracy of the IT SCED forecasted LMPs change as the cases approach real-time. In the final IT SCED results prior to real-time, in 38.4 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 41.3 percent in the 135 minute ahead IT SCED results.

Table 9-51 Differences between forecast and actual PJM/MISO interface prices: January through September, 2025

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	25.7%	$98.11	20.1%	$76.49	21.3%	$86.57	24.9%	$101.29
$10 to $20	10.5%	$14.18	10.2%	$14.28	10.0%	$14.24	9.1%	$14.34
$5 to $10	11.0%	$7.20	11.4%	$7.21	11.0%	$7.23	9.4%	$7.23
$0 to $5	24.4%	$2.15	24.9%	$2.13	22.5%	$2.18	18.3%	$2.20
$0 to -$5	16.9%	$1.84	19.0%	$1.88	19.4%	$1.97	20.1%	$2.13
-$5 to -$10	4.6%	$7.11	5.6%	$7.11	6.2%	$7.10	7.3%	$7.07
-$10 to -$20	2.9%	$14.14	3.8%	$14.22	4.3%	$14.11	5.1%	$14.01
< -$20	3.9%	$82.85	5.0%	$76.54	5.4%	$77.01	5.8%	$72.45

In 30.7 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $101.29 when the price difference was greater than $20.00, and $72.45 when the price difference was greater than -$20.00.

Table 9-52 and Table 9-53 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-52 Monthly differences between forecast and actual PJM/MISO interface prices (percent of intervals): January through September, 2025

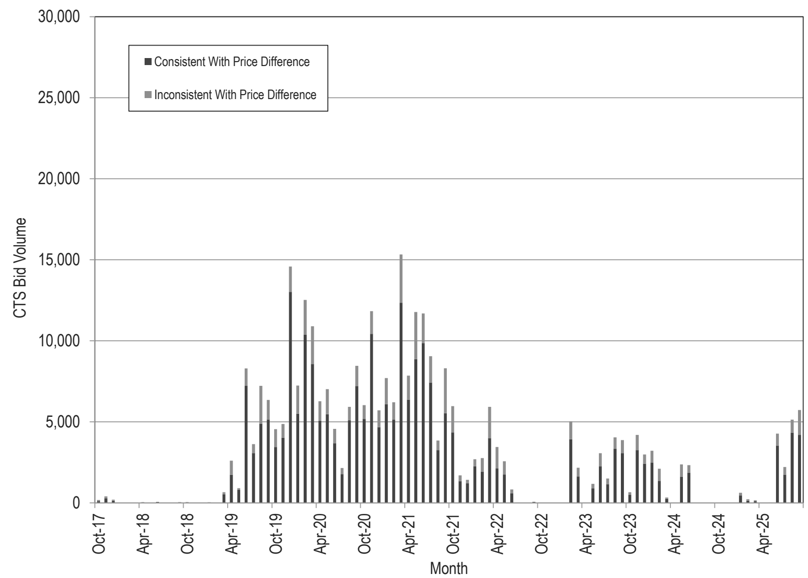
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	21.8%	21.6%	24.7%	33.9%	20.0%	25.9%	34.1%	20.0%	22.1%	24.9%
	$10 to $20	11.2%	8.6%	11.5%	12.5%	9.1%	6.8%	7.9%	7.4%	7.1%	9.1%
	$5 to $10	10.0%	13.1%	11.1%	10.0%	10.8%	7.9%	5.5%	7.9%	8.2%	9.4%
	$0 to $5	19.5%	18.6%	15.9%	13.9%	22.0%	19.6%	15.9%	20.5%	18.5%	18.3%
	$0 to -$5	17.6%	17.3%	14.3%	12.0%	24.0%	21.6%	22.1%	29.3%	22.3%	20.1%
	-$5 to -$10	6.4%	8.5%	8.0%	5.4%	6.7%	7.7%	7.2%	7.3%	8.8%	7.3%
	-$10 to -$20	6.3%	7.3%	6.6%	6.0%	3.3%	4.7%	3.6%	3.6%	5.1%	5.1%
	< -$20	7.3%	5.2%	7.9%	6.4%	4.1%	6.0%	3.6%	4.0%	7.9%	5.8%
Interval	**Range of Price Differences**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**YTD Avg**
~ 45 Minutes Prior to Real-Time	> $20	20.8%	21.2%	23.1%	33.9%	16.7%	21.1%	26.1%	12.9%	16.3%	21.3%
	$10 to $20	11.0%	9.1%	11.6%	11.9%	10.5%	7.2%	11.0%	9.1%	8.6%	10.0%
	$5 to $10	11.7%	12.7%	12.4%	11.2%	11.9%	9.3%	8.0%	9.7%	11.9%	11.0%
	$0 to $5	22.5%	20.4%	17.8%	15.2%	26.8%	25.8%	22.7%	28.1%	22.6%	22.5%
	$0 to -$5	17.4%	18.9%	15.3%	11.7%	21.2%	21.2%	19.6%	26.8%	22.0%	19.4%
	-$5 to -$10	6.1%	8.2%	7.1%	4.9%	5.3%	5.5%	5.5%	6.1%	7.2%	6.2%
	-$10 to -$20	5.3%	4.8%	5.5%	5.3%	3.7%	4.1%	3.5%	2.8%	3.5%	4.3%
	< -$20	5.1%	4.7%	7.1%	6.0%	3.9%	5.7%	3.6%	4.5%	8.0%	5.4%
Interval	**Range of Price Differences**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**YTD Avg**
~ 90 Minutes Prior to Real-Time	> $20	19.5%	16.4%	20.6%	28.3%	14.9%	21.6%	26.3%	14.4%	18.9%	20.1%
	$10 to $20	10.8%	11.6%	12.1%	12.6%	9.9%	7.8%	11.6%	7.9%	7.5%	10.2%
	$5 to $10	12.2%	12.7%	12.5%	12.5%	12.7%	9.7%	9.3%	9.8%	11.2%	11.4%
	$0 to $5	26.1%	23.2%	20.6%	16.8%	29.0%	28.3%	25.2%	29.6%	25.4%	24.9%
	$0 to -$5	17.4%	19.9%	15.3%	12.7%	21.8%	19.1%	17.7%	26.6%	20.2%	19.0%
	-$5 to -$10	5.3%	7.4%	6.5%	5.7%	4.6%	4.9%	4.4%	5.3%	6.5%	5.6%
	-$10 to -$20	4.2%	4.6%	5.3%	5.5%	3.3%	3.6%	2.3%	2.3%	2.9%	3.8%
	< -$20	4.7%	4.2%	7.2%	5.9%	3.7%	5.0%	3.2%	4.0%	7.4%	5.0%
Interval	**Range of Price Differences**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**YTD Avg**
~ 135 Minutes Prior to Real-Time	> $20	24.4%	26.6%	29.2%	30.4%	21.4%	24.3%	31.9%	18.5%	25.0%	25.7%
	$10 to $20	10.8%	10.4%	12.1%	12.8%	10.3%	8.0%	12.2%	8.7%	9.1%	10.5%
	$5 to $10	11.5%	9.8%	11.2%	11.6%	13.9%	10.7%	9.4%	10.5%	10.2%	11.0%
	$0 to $5	26.5%	21.7%	19.5%	18.3%	26.3%	29.2%	23.5%	29.9%	24.4%	24.4%
	$0 to -$5	15.7%	18.9%	13.6%	12.4%	19.4%	16.8%	15.1%	23.3%	17.2%	16.9%
	-$5 to -$10	4.9%	6.3%	5.3%	5.8%	3.5%	4.0%	3.1%	3.8%	5.3%	4.6%
	-$10 to -$20	3.2%	3.0%	4.4%	3.9%	2.7%	2.7%	1.9%	2.0%	2.7%	2.9%
	< -$20	3.1%	3.2%	4.7%	4.8%	2.6%	4.3%	2.8%	3.2%	6.1%	3.9%

Table 9-53 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through September, 2025

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$50.90	$63.03	$67.05	$59.38	$50.13	$209.69	$206.32	$69.02	$75.07	$101.29
	$10 to $20	$14.27	$14.22	$14.46	$14.55	$14.41	$14.45	$14.35	$14.29	$13.85	$14.34
	$5 to $10	$7.39	$7.25	$7.35	$7.30	$7.27	$6.88	$7.29	$7.07	$7.14	$7.23
	$0 to $5	$2.27	$2.44	$2.38	$2.46	$2.03	$2.19	$2.02	$2.05	$2.11	$2.20
	$0 to -$5	$2.13	$2.40	$2.33	$2.04	$2.06	$2.09	$2.13	$1.99	$2.17	$2.13
	-$5 to -$10	$7.06	$7.14	$7.37	$7.06	$7.10	$6.98	$7.01	$6.95	$6.93	$7.07
	-$10 to -$20	$14.41	$13.78	$14.02	$14.40	$13.67	$14.39	$13.40	$13.91	$13.71	$14.01
	< -$20	$42.68	$42.96	$59.52	$74.38	$60.50	$125.39	$65.17	$75.90	$98.98	$72.45
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$52.70	$64.14	$68.59	$67.90	$47.41	$170.25	$147.66	$68.31	$70.83	$86.57
	$10 to $20	$14.43	$14.40	$14.43	$14.17	$14.01	$14.18	$14.46	$14.05	$13.95	$14.24
	$5 to $10	$7.22	$7.12	$7.44	$7.37	$7.16	$7.10	$7.33	$7.10	$7.25	$7.23
	$0 to $5	$2.22	$2.39	$2.48	$2.26	$2.13	$2.28	$1.99	$1.94	$2.10	$2.18
	$0 to -$5	$2.05	$2.13	$2.17	$1.99	$1.88	$1.89	$1.92	$1.81	$2.03	$1.97
	-$5 to -$10	$7.14	$7.30	$7.19	$7.27	$7.06	$6.95	$7.04	$7.04	$6.91	$7.10
	-$10 to -$20	$14.34	$14.12	$14.39	$14.06	$14.15	$14.36	$13.60	$13.81	$13.76	$14.11
	< -$20	$44.80	$44.38	$61.12	$72.08	$64.00	$139.38	$72.24	$79.28	$97.65	$77.01
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$49.13	$48.23	$53.37	$60.00	$54.70	$147.58	$107.73	$78.60	$69.07	$76.49
	$10 to $20	$14.38	$14.41	$14.17	$14.41	$13.67	$14.38	$14.55	$14.27	$14.20	$14.28
	$5 to $10	$7.12	$7.22	$7.32	$7.40	$7.11	$6.89	$7.34	$7.18	$7.25	$7.21
	$0 to $5	$2.14	$2.30	$2.40	$2.18	$2.16	$2.12	$2.05	$1.88	$2.07	$2.13
	$0 to -$5	$1.99	$1.97	$2.21	$2.00	$1.75	$1.81	$1.77	$1.69	$1.97	$1.88
	-$5 to -$10	$7.01	$7.24	$7.21	$7.25	$7.10	$6.93	$7.09	$7.01	$7.04	$7.11
	-$10 to -$20	$14.48	$14.05	$14.41	$14.70	$13.96	$14.15	$13.88	$13.96	$13.74	$14.22
	< -$20	$48.62	$47.02	$63.09	$76.18	$64.14	$116.58	$75.12	$84.73	$99.55	$76.54
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$81.50	$88.41	$97.10	$84.07	$88.74	$148.40	$102.36	$86.56	$105.57	$98.11
	$10 to $20	$14.45	$14.28	$14.40	$14.00	$14.19	$13.90	$14.33	$13.97	$13.95	$14.18
	$5 to $10	$7.11	$7.23	$7.37	$7.37	$7.06	$7.06	$7.25	$7.17	$7.18	$7.20
	$0 to $5	$2.15	$2.16	$2.43	$2.22	$2.16	$2.13	$2.14	$1.95	$2.13	$2.15
	$0 to -$5	$1.89	$2.02	$2.11	$1.94	$1.71	$1.74	$1.80	$1.69	$1.85	$1.84
	-$5 to -$10	$7.09	$7.07	$7.14	$7.17	$7.18	$7.20	$7.11	$7.02	$7.05	$7.11
	-$10 to -$20	$14.33	$14.14	$14.22	$14.09	$14.12	$13.86	$13.79	$14.77	$13.87	$14.14
	< -$20	$50.61	$46.71	$66.71	$82.44	$74.47	$130.98	$71.21	$92.23	$101.37	$82.85

CTS transactions were evaluated for each interval. From October 3, 2017, through September 30, 2025, 309,913 CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 63,324 (20.4 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 20.4 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 79.6 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 9-12 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 9-12 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences. In June 2022, MISO experienced software issues that prevented the submission and clearing of CTS transactions. The issue was resolved in August 2022. It is unclear why market participants did not resume scheduling CTS transactions at the MISO interface until February 2023. Market participants did not use the MISO CTS transaction option between June 2024 and January 2025. While the forecast LMPs have not proven to be a good predictor of real time LMPs, that has not changed. It is not clear why market participants stopped using the MISO CTS transaction option during that time, or have not resumed using the option at volumes previously used.

Figure 9-12 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through September 30, 2025



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-54 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only two months (January 2016 and February 2019). In both months, there was negative uncollected congestion. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in both January 2016 and February 2019.

Table 9-54 Monthly uncollected congestion charges: January 2010 through September 2025

Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0	($69,992)	$0	$0	$0	$0	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0	($69,992)	$0	$0	$0	$0	$0	$0

Transmission Service Requests

Requests for transmission service are made on the PJM Open Access Same Time Information System (OASIS) on any of the posted paths. The products available on the OASIS include both firm and nonfirm service. Nonfirm service is available on an hourly, daily, weekly and monthly basis. Firm transmission service is defined as either short term or long term firm. Short term firm transmission is available on a daily, weekly or monthly basis, and long term firm is available for a period of one year or longer.

The total transfer capability (TTC) reflects the maximum amount of power that can be transferred over a transmission line or a group of transmission lines. In order to maintain reliability, transmission providers do not make the entire TTC available to be used. The available flowgate capability (AFC) is calculated for each path and product pair by taking the TTC and subtracting existing service requests, a capacity benefit margin[65], a transmission reliability margin[66] and taking postbacks and counterflows into consideration. The amount of transmission service that can be reserved is the Available Transfer Capability (ATC). The ATC is calculated for each path and product, and is determined by taking the AFC and adjusting it for all other committed transmission service requests that impact that path.

PJM calculates and posts ATC for all valid posted paths product pairs. The range of calculated ATCs depends on the duration of service. Hourly service is available up to seven days in advance, daily service is available 35 days in advance, weekly service is available five weeks in advance and monthly service is available 18 months in advance. Any transmission request that falls within the posted ATC period is evaluated based on the posted ATC. If there is sufficient capability, the transmission service request is accepted. If there is not sufficient capability, the transmission service request is denied.

Long term firm transmission service requests that extend beyond the ATC posting calculation are subject to system impact studies and must be submitted and evaluated in the new services queue. There is currently a backlog of projects in the new services queue. The backlog is being resolved through a transition to a new planning process, but new transmission service requests may not be evaluated or approved until 2027.[67]

65 The capacity benefit margin is defined by NERC as "the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

66 The transmission reliability margin is defined by NERC as "the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure".

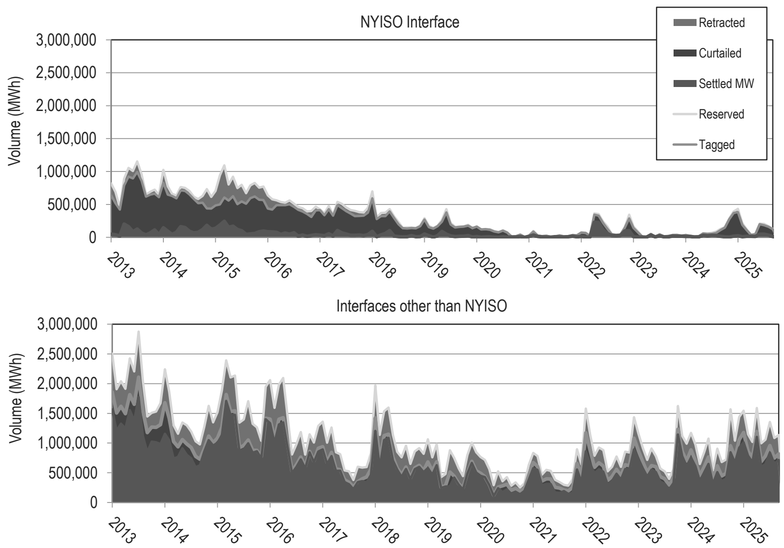
67 See the *2025 Quarterly State of the Market Report for PJM: January through September*, Section 12, "Generation and Transmission Planning," for additional details.

Spot Imports

Figure 9-13 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through September 30, 2025. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service. This area may also represent hoarding opportunities, particularly at the NYISO Interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding the transmission from other market participants that may wish to use it. The green shaded area represents the total settled MWh of spot import service. Figure 9-13 shows that while there are proportionally fewer retracted MWh on the NYISO Interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.[68]

68 See the *2018 Annual State of the Market Report for PJM*, Volume 2, Section 9, "Interchange Transactions," for a more complete discussion of the history of spot import transmission service.

Figure 9-13 Spot import service use: January 2013 through September 2025



The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm point to point willing to pay congestion imports and exports) at all PJM interfaces.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible for PJM system operators to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 (EPT) on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[69] These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point to point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, are dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange

69 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes. See *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, order on reh'g, Order No. 764-A, 141 FERC ¶ 61231 (2012).

then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is based on the assumption that the available generation in the PJM system can only move 1,000 MW over any 15 minute period, although there is no supporting analysis. As an example of how the ramp limit works, if at 0800 (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intrahour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with relatively little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[70] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[71]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[72]

MISO Multi-Value Project Usage Rate (MUR)

MISO defines a multi-value project (MVP) to be a project which, according to MISO, enables the reliable and economic delivery of energy in support of

70 *Id.* at P 51.
71 See *Id.* at P 12.
72 See joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value. On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[73] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[74] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

On June 7, 2014, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP Order and MVP Rehearing Order.[75] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[76] The Seventh Circuit highlighted the fact that at the time of the Commission's decision to prohibit rate pancaking on transactions between MISO and PJM, all of MISO's transmission projects were local and provided only local benefits.[77]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[78] The July 13th Order noted that in light of "the development of large scale wind generation capable of serving both MISO's and its neighbors' energy policy requirements in the western areas of MISO; the reported need of PJM entities to access those resources; and the reported need for MISO to build new transmission facilities to deliver the output of those resources within MISO for export… it is appropriate to allow MISO to assess the MVP usage charge for transmission service used to export to PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions."[79]

The policy rationale for permitting MISO to impose transmission costs on PJM market participants without clear criteria is weak and results in pancaking of rates. The impact is expected to increase.

Table 9-55 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2024 through 2045.[80] As shown in Table 9-4, there were 4,672.1 GWh of imports from MISO in the first nine months of 2025. At the 2025 MUR of $1.57 per MWh, PJM market participants paid $7.3 million towards the costs of MISO's multi value projects. It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-55 MISO projected multi value project usage rate: 2025 through 2045

Year	Total Indicative MVP Usage Rate ($/MWh)
2025	$1.57
2026	$1.58
2027	$1.56
2028	$1.53
2029	$1.50
2030	$1.47
2031	$1.44
2032	$1.41
2033	$1.39
2034	$1.36
2035	$1.33
2036	$1.31
2037	$1.28
2038	$1.26
2039	$1.23
2040	$1.21
2041	$1.18
2042	$1.16
2043	$1.13
2044	$1.11
2045	$1.09

73 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
74 133 FERC ¶ 61,221; *order on reh'g*, 137 FERC ¶ 61,074 (2011).
75 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
76 *Id.* at 780.
77 *Id.* at 779.
78 156 FERC ¶ 61,034 (2016).
79 *Id.* at P 55.
80 See MISO, "Schedule 26A Indicative Annual Charges," (March 20, 2025) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.

Ancillary Service Markets

FERC defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve - spinning reserve service; and operating reserve - supplemental reserve service.[1] PJM provides scheduling, system control and dispatch as part of the PJM administrative function. PJM provides reactive on what is asserted to be a cost of service basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] The PJM ancillary service markets are regulation, synchronized reserve, primary reserve, and 30-minute reserve. Although not defined by FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of formula rates and cost of service rates.

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first nine months of 2025.

Table 10-1 The synchronized reserve market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The synchronized reserve market structure was evaluated as not competitive due to supplier concentration. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market. The MAD Reserve Subzone was moderately concentrated in the day-ahead market and moderately concentrated in the real-time market.
- Participant behavior was evaluated as competitive because the market rules require all available reserves to offer at cost-based offers.
- Market performance was evaluated as not competitive because the interaction of participant behavior with the market design does not result in competitive prices as a result of PJM's changes to the operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023, raising prices for synchronized reserves, nonsynchronized reserves and energy.
- Market design was evaluated as flawed based on PJM's modifications to the ORDC. PJM previously adopted reforms, including several based on MMU recommendations, removing both physical and economic withholding from the market.
- Significant communications technology issues when calling resources during synchronized reserve events have resulted in slow response from resources. On December 17, 2024, PJM implemented an electronic deployment of reserves via an augmented dispatch signal, but PJM does not require that resources be able to receive this signal.

The MMU analyzed measures of market structure, conduct and performance for the PJM Nonsynchronized Reserve Market for the first nine months of 2025.

Table 10-2 The nonsynchronized reserve market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The nonsynchronized reserve market structure was evaluated as not competitive due to supplier concentration for primary reserve. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market. The MAD Reserve Subzone was moderately concentrated in the day-ahead market and moderately concentrated in the real-time market.

1 See 75 FERC ¶ 61,080 (1996). PJM renamed spinning reserve as synchronized reserve based on PJM's inclusion of demand side resources in the product.
2 Energy imbalance service refers to the real-time energy market.

- Participant behavior was evaluated as competitive because all available reserves are included by the PJM markets software, so withholding is not possible.
- Market performance was evaluated as not competitive because the interaction of participant behavior with the market design does not result in competitive prices as a result of PJM's changes to the operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023. Because the first step of the ORDC for primary reserve, known as the primary reserve reliability requirement, is based on the synchronized reserve reliability requirement, the primary reserve reliability requirement was consequently also extended, raising prices for synchronized reserves, nonsynchronized reserves, and energy.
- Market design was evaluated as flawed based on PJM's modifications to the first step of the ORDC.

The MMU analyzed measures of market structure, conduct and performance for the PJM Secondary Reserve Market for the first nine months of 2025.

Table 10-3 The secondary reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The secondary reserve market structure was evaluated as competitive due to the lack of supplier concentration for 30-minute reserve. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM software, so withholding is not possible.
- Market performance was evaluated as competitive because the combination of a competitive market structure and competitive participation resulted in competitive market outcomes.
- The market design was evaluated as effective because the market rules ensure competitive market offers and require repayment of offline cleared secondary reserves that are not available when called on to provide energy in 30 minutes.

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first nine months of 2025.

Table 10-4 The regulation market results were not competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 94.2 percent of the hours in the first nine months of 2025.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first nine months of 2025 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin is not consistent with competitive offers.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

Primary reserves consist of both synchronized and nonsynchronized reserves that can provide energy within 10 minutes and sustain that output for at least 30 minutes during a contingency event. PJM made several changes to the primary reserve market, effective October 1, 2022. These included a must offer requirement and correction of misspecified cost-based offers. By removing opportunities for physical and economic withholding, the changes resulted in clearing increased quantities of available synchronized reserves at competitive prices. Starting in May 2023, to compensate for poor unit specific resource performance, PJM unilaterally increased the synchronized reserve reliability requirement, which in turn increased the primary reserve reliability requirement.

Market Structure

- **Supply.** Primary reserve is provided by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes) and nonsynchronized reserve (generation currently offline but available to start and provide energy within 10 minutes).
- **Demand.** The primary reserve reliability requirement is equal to 150 percent of the synchronized reserve reliability requirement. The primary reserve requirement is equal to the primary reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement (190 MW), with a shortage penalty price of $300 per MWh. The synchronized reserve requirement is equal to the synchronized reserve reliability requirement plus the extended reserve requirement, with a default level of 190 MW. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Starting in May 2023, PJM increased the size of the synchronized reserve reliability requirement in the RTO Reserve Zone by 30 percentage points to 130 percent of the most severe single contingency (MSSC), in effect increasing the primary reserve reliability requirement to 195 percent of the MSSC. In the first nine months of 2025, the real-time average primary reserve requirement was 3,401.4 MW in the RTO Reserve Zone and 2,584.7 MW in the Mid-Atlantic Dominion Reserve Subzone. In the first nine months of 2025, the day-ahead average primary reserve requirement was 3,384.4 MW in the RTO Reserve Zone and 2,559.0 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** Both the Mid-Atlantic Dominion (MAD) Reserve Subzone Market and the RTO Reserve Zone Market for primary reserve were characterized by structural market power in the first nine months of 2025. The average HHI for real-time primary reserve in the RTO Reserve Zone was 980, which is classified as unconcentrated. The average HHI for day-ahead primary reserve in the RTO Zone was 915, which is classified as unconcentrated. The average HHI for real-time primary reserve in the MAD Reserve Subzone was 1563, which is classified as moderately concentrated. The average HHI for day-ahead primary reserve in the MAD Reserve Subzone was 1401, which is classified as moderately concentrated.

Synchronized Reserve Market

Synchronized reserves include all capacity synchronized to the grid and available to satisfy PJM's power balance requirements within 10 minutes. This includes online resources loaded below their full output, storage or condensing resources synchronized to the grid but consuming energy, and 10-minute demand response capability. As of October 1, 2022, all generation capacity resources must offer their entire synchronized reserve capability to the PJM market at all times. PJM jointly optimizes energy, synchronized reserve, primary reserve, and 30-minute reserve needs in both the day-ahead and real-time markets. Synchronized reserve prices are based on opportunity costs calculated by PJM in the market optimization and the anticipated cost of a performance penalty. All real-time cleared synchronized reserves are obligated to perform when PJM initiates a synchronized reserve event based on a loss of supply.

Market Structure

- **Supply.** In the first nine months of 2025, the real-time average supply of available synchronized reserve was 5,763.4 MW in the RTO Reserve Zone, of which 2,814.0 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone. In the first nine months of 2025, the day-ahead average supply of available synchronized reserve was 6,664.6 MW in the RTO Reserve Zone, of which 3,392.5 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** The synchronized reserve requirement is equal to the synchronized reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement, with a shortage penalty price of $300 per MWh and a default value of 190 MW. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Since May 19, 2023, PJM has inappropriately set the synchronized reserve reliability requirement to 130 percent of the MSSC for the RTO Reserve Zone. The real-time average synchronized reserve requirement in the first nine months of 2025 was 2,330.9 MW in the RTO Reserve Zone and 1,786.4 MW in the Mid-Atlantic Dominion Reserve Subzone. The day-ahead average synchronized reserve requirement in the first nine months of 2025 was 2,319.6 MW in the RTO Reserve Zone and 1,769.4 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion (MAD) Reserve Subzone Market for synchronized reserve was characterized by structural market power in the first nine months of 2025. The average HHI for real-time synchronized reserve in the RTO Reserve Zone was 911, which is classified as unconcentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 799, which is classified as unconcentrated. The average HHI for real-time synchronized reserve in the MAD Reserve Subzone was 1721, which is classified as moderately concentrated. The average HHI for day-ahead synchronized reserve in the MAD Reserve Subzone was 1341, which is classified as moderately concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for synchronized reserve. All nonemergency generation capacity resources are required to offer their entire synchronized reserve capability. PJM calculates the available synchronized reserve for all conventional resources based on the energy offer ramp rate, energy dispatch point, and the lesser of the synchronized reserve maximum or economic maximum output. Hydro resources, energy storage resources, and demand response resources submit their available synchronized reserve MW. Wind, solar, and nuclear resources are by default considered incapable of providing synchronized reserve, but may offer with an exception approved by PJM. Synchronized reserve offers are capped at cost plus the expected value of performance penalties. PJM calculates opportunity costs based on LMP.

  Significant communications technology and modelling issues when calling resources during spinning events continue to result in slow response from a significant share of resources.

Market Performance

- **Price.** In the first nine months of 2025, for the Mid-Atlantic Dominion Reserve Subzone, the weighted average real-time price for synchronized reserve was $3.94 per MWh and the weighted average day-ahead price was $6.26 per MWh. In the first nine months of 2025, for the RTO Reserve Zone, the weighted average real-time price for synchronized reserve was $4.55 per MWh and the weighted average day-ahead price was $6.23 per MWh.

Nonsynchronized Reserve

Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to meet the portions of the primary reserve requirement and the 30-minute reserve requirement not already satisfied by reserve cleared for the synchronized reserve requirement.

Market Structure

- **Supply.** In the first nine months of 2025, the real-time average supply of eligible and available nonsynchronized reserve was 1,006.5 MW in the RTO Reserve Zone, of which 614.1 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone. In the first nine months of 2025, the real-time average supply of eligible and available nonsynchronized reserve was 1,039.6 MW in the RTO Reserve Zone, of which 476.9 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** Demand for nonsynchronized reserve is the primary reserve requirement less the amount of synchronized reserves cleared by PJM.[3] Although nonsynchronized reserve can be used to meet the 30-minute reserve requirement, any 30-minute reserve beyond the primary reserve requirement is usually provided by secondary reserve due to its lower cost and greater availability.

Market Conduct

- **Offers.** Generation owners do not submit supply offers for nonsynchronized reserve from non-hydroelectric units. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are defined to be available for nonsynchronized reserves. For non-hydroelectric units, PJM calculates the MW available from a unit based on the unit's energy offer. Hydroelectric units set their own offered reserve amount. For all units, the offer price of nonsynchronized reserve is $0 per MWh.[4] Hybrid units and energy storage resources are not eligible to provide nonsynchronized reserves.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the marginal primary reserve resource. In the first nine months of 2025, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $1.87 per MWh and the weighted average day-ahead price was $2.42 per MWh. In the first nine months of 2025, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $2.22 per MWh and the weighted average day-ahead price was $3.43 per MWh.

30-Minute Reserve Market

The supply of 30-minute reserves consists of resources, online or offline, which can respond within 30 minutes. This includes primary reserves and secondary reserves. There is no reserve subzone for 30-minute reserves.

Market Structure

- **Supply.** The supply of 30-minute reserve is provided by both primary reserve (synchronized and nonsynchronized resources that can provide energy within 10 minutes) and secondary reserve (synchronized and nonsynchronized resources that can provide energy within 30 minutes but that take more than 10 minutes). In the first nine months of 2025, the real-time average supply of available 30-minute reserve was 27,655.6 MW in the RTO Zone.
- **Demand.** The 30-minute reserve requirement is equal to the 30-minute reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement (190 MW), with a shortage penalty price of $300 per MWh. The 30-minute reserve reliability requirement is equal to the maximum of: the primary reserve reliability requirement; the largest active gas contingency; and 3,000 MW. Since PJM increased the synchronized reserve reliability requirement, the 30-minute reserve reliability requirement is frequently equal to the primary reserve reliability requirement. In the first nine months of 2025, the average 30-minute reserve requirement was 3,519.5 MW in the real-time market and 3,508.8 MW in the day-ahead market.
- **Market Concentration.** The RTO Reserve Zone Market for 30-minute reserves was characterized by moderate structural market power in the first nine months of 2025. In the first nine months of 2025, the average HHI for real-time 30-minute reserves was 869, which is classified as

3 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 134 (Apr. 23, 2025).
4 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 134 (Apr. 23, 2025).

unconcentrated. In the first nine months of 2025, the average HHI for day-ahead 30-minute reserves was 857, which is classified as unconcentrated.

Secondary Reserve

Secondary reserves are reserves that take more than 10 minutes to convert to energy, but less than 30 minutes. This includes the unloaded capacity of online generation that can be achieved according to the resource ramp rates in 10 to 30 minutes, and offline resources with a start time of less than 30 minutes. Secondary reserves can only be used to satisfy the 30-minute reserve requirement.

Market Structure

- **Supply.** In the first nine months of 2025, in the RTO Reserve Zone, the real-time average supply of available secondary reserve was 21,163.8 MW and the day-ahead average supply of available secondary reserve was 12,402.1 MW. As with the 30-minute reserve service, there is no defined reserve subzone for secondary reserves.
- **Demand.** Demand for secondary reserve is the 30-minute reserve requirement less the amount of primary reserves cleared by PJM.[5]

Market Conduct

- **Offers.** Energy storage resources, hydroelectric resources, hybrid resources, and demand-side response resources submit their available secondary reserve MW. For all other resource types, PJM calculates the MW available from a resource based on the resource's energy offer. For all resources, the offer price of secondary reserve is $0 per MWh.[6] In both the day-ahead and real-time secondary reserves markets, PJM uses lost opportunity costs as the offers and not offers submitted by market participants. For online secondary reserves, PJM calculates an opportunity cost based on LMP.

5 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 134 (Apr. 23, 2025).
6 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 134 (Apr. 23, 2025).

Market Performance

- **Price.** The secondary reserve price is determined by the marginal 30-minute reserve resource. In the first nine months of 2025, the secondary reserve real-time price for all intervals was $0.01 per MWh. In the first nine months of 2025, the secondary reserve day-ahead price for all intervals was $0.00 per MWh.

Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp rates. The RegD signal is designed for energy limited resources with fast ramp rates. In the regulation market RegD MW are converted to effective MW using a marginal rate of technical substitution (MRTS), called a marginal benefit factor (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the regulation market.

PJM filed significant changes to the regulation market design on April 16, 2024, that were accepted as filed by order of June 17, 2024.[7] PJM will implement the changes to the regulation market in two phases. Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The proposed Phase 1 changes will eliminate many of the significant issues identified by the MMU that have resulted from a two product, two signal market design including the incorrect and inconsistent use and application of the MBF/MRTS.

7 PJM, "Regulation Market Design Filing," Docket No. ER24-1772-000 (April 16, 2024).

This report analyzes the current (as of the third quarter of 2025) regulation market design and results during the first nine months of 2025.

Market Structure

- **Supply.** In the first nine months of 2025, the average hourly offered supply of regulation for nonramp hours was 788.7 performance adjusted MW (787.2 effective MW). This was an increase of 93.2 performance adjusted MW (an increase of 78.9 effective MW) from the first nine months of 2024, when the average hourly offered supply of regulation was 695.5 actual MW (708.3 effective MW). In the first nine months of 2025, the average hourly offered supply of regulation for ramp hours was 1,063.0 performance adjusted MW (1,119.1 effective MW). This was an increase of 68.6 performance adjusted MW (an increase of 72.1 effective MW) from the first nine months of 2024, when the average hourly offered supply of regulation was 994.4 performance adjusted MW (1,047.0 effective MW).
- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 486.9 hourly average performance adjusted actual MW in the first nine months of 2025. This is an increase of 8.3 performance adjusted actual MW from the first nine months of 2024, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 478.5 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 690.8 hourly average performance adjusted actual MW in the first nine months of 2025. This is a decrease of 6.6 performance adjusted actual MW from the first nine months of 2024, where the average hourly regulation cleared MW for ramp hours were 697.5 performance adjusted actual MW.

  The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.62 in the first nine months of 2025 (1.45 in the first nine months of 2024). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.54 in the first nine months of 2025 (1.42 in the first nine months of 2024).
- **Market Concentration.** In the first nine months of 2025, the three pivotal supplier test was failed in 94.2 percent of hours. In the first nine months of 2025, the effective MW weighted average HHI of RegA resources was 2632 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 2015 which is also highly concentrated. The effective MW weighted average HHI of all resources was 1315, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[8] In the first nine months of 2025, there were 193 resources following the RegA signal and 60 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $42.42 per MW of regulation in the first nine months of 2025, an increase of $11.12 per MW, or 35.5 percent, from the weighted average clearing price of $31.30 per MW in the first nine months of 2024. The weighted average cost of regulation in the first nine months of 2025 was $52.35 per MW of regulation, an increase of 33.2 percent, from the weighted average cost of $39.31 per MW in the first nine months of 2024.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the

8 See the *2024 Annual State of the Market Report for PJM*, Appendix F "Ancillary Services Markets."

regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW.

- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[9]

In the first nine months of 2025, total black start charges were $39.6 million, a decrease of $15.6 million (28.3 percent) from 2024. In the first nine months of 2025, total revenue requirement charges were $39.2 million, a decrease of $15.7 million (28.6 percent) from 2024. In the first nine months of 2025, total black start uplift charges were $0.4 million, a increase of $.01 million (30.4 percent) from 2024. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive payment. Black start uplift charges are paid to units scheduled in the day-ahead energy market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in the first nine months of 2025 ranged from $0 in the OVEC and REC Zones to $6.6 million in the AEP Zone.

CRF values are a key determinant of total payments to black start units. The CRF values in PJM tariff tables should have been changed for both black start and the capacity market when the tax laws changed effective January 1, 2018. As a result of the failure to reduce the CRF values, black start units have been and continue to be significantly overcompensated since the changes to the tax code. In March 2023, FERC issued an order establishing hearing and settlement judge procedures.[10] By order issued September 23, 2025, the Commission approved a settlement over the MMU's objection that continued to allow overcompensation.[11] On July 4, 2025, enactment of the One Big Beautiful Bill Act (OBBBA) changed the rules for bonus depreciation again, allowing 100 percent bonus depreciation for assets constructed between January 20, 2025 and December 31, 2028, and placed in service before January 1, 2031.[12] The CRF values for affected units should incorporate 100 percent bonus depreciation. It is essential that PJM not repeat its earlier mistake when it ignored the tax law changes in 2017.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVAr and MW. Generation resources are required to meet defined reactive capability requirements as a condition to receive interconnection service in PJM.[13] RTOs and their customers are not required to separately compensate generation resources for such reactive capability.[14] In the first nine months of 2025, PJM customers paid $273.1 million for reactive capability based on archaic, nonmarket and unsupported assertions about cost allocation and a regulatory review process of filings by individual units that results in unsupported black box settlements. The current rules have permitted over recovery of reactive costs through reactive capability charges. All costs of generators should be incorporated in the market.

9 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.

10 See 182 FERC ¶ 61,194.
11 See 193 FERC ¶ 61,059.
12 OBBA § 70301(b)(3).
13 OATT Attachment O.
14 See 182 FERC ¶ 61,033 at P 52 (2023); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *California ISO*, 160 FERC ¶ 61,035 at P 19 (2017); 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022).

The nonmarket approach to reactive capability payments will be eliminated effective June 1, 2026, based on FERC's Order No. 904 and the order approving PJM's compliance filing.[15]

Reactive service charges based on opportunity costs are appropriately paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing real-time reactive power.

In the first nine months of 2025, total reactive charges were $273.7 million, a decrease of $12.1 million (4.24 percent) from 2024. In the first nine months of 2025, total reactive capability charges were $273.1 million, a decrease of $11.7 million (4.1 percent) from 2024. In the first nine months of 2025, total reactive service charges were $0.59 million, a decrease of $0.41 million (41.4 percent) from 2024.

Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $28.6 million in the AEP Zone in the first nine months of 2025.

Primary Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require all newly interconnecting non-nuclear generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[16]

Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 Hz deadband.[17] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events occurs two to three times per month. A frequency event is declared whenever the system frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz. Exclusions to PJM monitoring include nuclear plants, offline units, units with no available headroom, units assigned to regulation, and units with a current outage ticket in eDART. Effective June 2024 through June 2025, the NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to +/- 258.3 MW/0.1 Hz.[18]

The MMU has identified several issues with PJM's enforcement and evaluation of generation PFR performance.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services including synchronized reserves, primary reserves and 30-minute reserves, and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be included in the offer for the ancillary service. The degree to which PJM markets account for these interactions depends on the timing of the product clearing, software limitations, and the accuracy of resource parameters and offers.

All reserve products are jointly cleared with energy in every real-time market solution. The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services because dispatched energy and synchronized reserve are outputs of the same optimization problem for each market interval. Given the joint clearing of energy and flexible synchronized reserves, the synchronized reserve market clearing price should

15 See *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024); PJM compliance filing, Docket No. ER24-1073 (January 28, 2025); 192 FERC ¶ 61,113 (2025).
16 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.
17 OATT Attachment O § 4.7.2 (Primary Frequency Response).
18 See NERC. "2024 Frequency Bias Settings," June 11, 2024. <https://www.nerc.com/comm/OC/Documents/OY_2024_Frequency_Bias_Annual_Calculations_correction_06112024.pdf>.

always cover the opportunity cost of providing flexible synchronized reserves. Inflexible synchronized reserves, provided by resources that require hourly commitments due to run-time or staffing constraints, are not cleared with energy in the real-time market solution.[19] Instead, inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the day-ahead energy market. The ASO considers energy market price forecasts, availability of resources for flexible synchronized reserves, and regulation requirements to estimate the costs and benefits of using a resource for inflexible synchronized reserves. The ASO selected inflexible reserves are a fixed input to RT SCED, which clears the balance of the requirement with flexible synchronized reserves.

Nonsynchronized reserves and offline secondary reserves are cleared with every real-time energy market solution. The energy commitment decisions to keep the resources offline have already been made when the RT SCED clears the five-minute reserves markets. Therefore, offline reserves have no lost opportunity cost. They will not be called on for energy during the market interval for which they are assigned as offline resources.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which uses the RT SCED solution as an input. The LPC includes fast start pricing logic and system marginal price caps, so the final prices can be inconsistent with the marginal cost of the resources that clear regulation and reserves.

Recommendations

Reserve Markets

- The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and automatically respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted 2024.)
- The MMU recommends that PJM replace the Mid-Atlantic Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Partially adopted 2022.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the unit repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the synchronized reserve shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM immediately remove the 30 percent increase to the synchronized reserve reliability requirement. (Priority: High. First reported 2024. Status: Not adopted.)

Regulation Market

- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. First reported 2023. Status: Not adopted.)[20]
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed

19 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Reserve Market Clearing, Rev. 134 (Apr. 23, 2025).

20 PJM filed proposed changes to the regulation market with the FERC on April 16, 2024, (Regulation Market Design Filing," Docket No. ER24-1772-000). The Commission Order on June 17, 2024 accepted the PJM Proposal as filed. PJM will implement the changes to the regulation market in two phases. Phase 1, scheduled to be implemented on October 1, 2025, will result in a single signal, bidirectional market with one clearing price that eliminates the need for an MBF. Phase 1 will eliminate RegA and RegD dual offers. Phase 1 will reduce the regulation commitment period from a 60-minute commitment to a 30-minute commitment. In Phase 1 the lost opportunity cost calculation used in the regulation market will be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule.

from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)[21]

- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.)[22]
- The MMU recommends that the current calculation of the performance score (based on precision, delay and correlation metrics) be replaced with the current calculation of the precision score. (Priority: Medium. First reported 2023. Status: Not adopted.).
- The MMU recommends that the regulation market commitment period be reduced from a 60-minute commitment to a 30-minute commitment. (Priority: Medium. First reported 2023. Status: Not adopted.).[23]
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[24] FERC rejected.)[25]
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[26]
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW. (Priority: Medium. First reported 2022. Status: Not adopted.)[27]
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[28]
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.)[29]

Frequency Response, Reactive, and Black Start

- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Partially adopted.)

21 See *id.*
22 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
23 See *id.*
24 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
25 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
26 See *id.*
27 In Phase 1 the ramp rate limited desired MW output will be used in the regulation uplift calculation. The MMU does not agree with how this change will be implemented and will be reviewing the market results in Phase 1.
28 See *id.*
29 See *id.*

- The MMU recommends that all data necessary to perform the generator primary frequency response evaluation be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM maintain a full list of all units subject to the Primary Frequency Response generator requirements. (Priority: Medium. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that PJM develop the metric(s) necessary to objectively evaluate each unit's performance during primary frequency response events. (Priority: Medium. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that PJM create the necessary tariff/manual language to properly enforce compliance with the NERC mandated Primary Frequency Response generator requirements. (Priority: Medium. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in PJM markets. (Priority: Medium. First reported 2016. Status: Adopted 2024.)[30]
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.95 power factor included in the voltage schedule in Interconnection Service Agreements. (Priority: Medium. First reported 2018. Status: Not adopted.)[31]
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019. Status: Not adopted.)[32]
- The MMU recommends that, if payments for reactive are continued, Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. (Priority: Medium. First reported 2020. Status: Not adopted.)[33]
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. Black start units should be required to commit to providing black start service for the life of the unit. CRF rates effective January 20, 2025, should reflect 100 percent bonus depreciation.[34] (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely zonal basis and that the costs of black start service be shared on an equal per MWh basis across the region. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that the Reliability Backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources. (Priority: High. First reported Q2, 2025. Status: Not adopted.)

Conclusion

The October 1, 2022, changes to the reserve markets included a synchronized reserve must offer requirement applicable to all generation capacity resources. This resulted in an increase in available supply. Combined with the removal of the $7.50 per MWh margin and the invalid variable operations and maintenance cost, supply and demand logic predicts lower prices, which occurred in 2022, except during Winter Storm Elliott. This is evidence of market efficiency. With the elimination of tier 1 reserves, the total reserve market clearing price credits, while based on lower prices, are paid to a larger

30 On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM. On January 28, 2025, PJM submitted a compliance filing to implement Order No. 904 ("Compliance Filing") that proposed a transition mechanism lasting through May 31, 2026. See Docket No. ER25-1073. This recommendation will be implemented effective June 1, 2026.
31 *Id.* FERC Order No. 904 eliminates payments for reactive capability. When Order 904 is in effect, which is planned for June 1, 2026, this recommendation will be withdrawn as no longer relevant.
32 *Id.*
33 *Id.*
34 OBBA § 70301(b)(3).

MW quantity. Prices have been higher since PJM increased the demand for reserves in May 2023.

The new reserve market design has been called into question by PJM based on a slow response during synchronized reserve events. In all cases, other than during Winter Storm Elliott, the ACE recovered within the required time frame. No reliability problems have occurred. While the total response met the needs of the system, PJM responded to the poor performance of individual units by unilaterally and inappropriately increasing reserve requirements. This increase shifts the burden of poor resource performance from the resources themselves to customers, clearing more reserves instead of directly dealing with the causes of poor performance. These increases in reserve requirements were the primary cause of higher reserve prices in 2023, 2024, and the first nine months of 2025, including 35 intervals of shortage pricing in May 2023 and several intervals of shortage pricing during spin events in 2024 and the first nine months of 2025, even while reserve markets cleared over 1,000 MW more than what was normally cleared in the months and years prior.

The data on synchronized reserve event recovery do not support the conclusion that there was or is a need to increase the demand for reserves. The focus should be on correcting issues related to the responses of individual units rather than increasing demand.

Significant communications technology and modelling issues when calling resources during spinning events result in slow response. While PJM now calculates reserve offer MW for the majority of resource types, a resource's cleared reserve MW are based on a resource's energy output at the end of a scheduling interval. If a unit is still moving when an event is called, such as near the beginning of a scheduling interval, it may or may not be able to achieve its scheduled output. Likewise, a unit that is decreasing output to create more headroom might not be able to immediately increase output when an event is called.

Although PJM now augments a resource's economic basepoint with its dispatched reserve MW during a spin event, PJM does not require resources to be able to receive this signal. Many resources are still dispatched using phone calls, either from markets operation centers waiting for the PJM ALL-CALL or from MOCs themselves manually calling plant personnel.

Even if a unit is on AGC and receiving the augmented basepoint, depending on where that unit finds itself on its ramp rate curve, it might have to spend time coming off AGC or decreasing output in order to start ramping using power augmentation. Having a synchronized reserve maximum that is less than the unit's economic maximum can address this case, but it is the responsibility of that unit to request the exception.

The immediate solution is to improve the deployment of reserves in synchronized reserve events by requiring the capability to use an electronic signal for all synchronized reserves and the actual use of the signal. The archaic telephone communications technology has been a source of slow response times, such as markets operation centers waiting for the PJM ALL-CALL or manually calling unit personnel to deploy reserves. Phone calls are not an effective or efficient method for deploying resources for immediate response. The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and automatically respond to the notifications. On December 17, 2024, PJM partially adopted this recommendation by implementing an electronic deployment of reserves via an augmented dispatch signal, but PJM does not require that resources be able to receive this signal nor that the receiving units be able to follow the signal for deploying reserves. Further improvements in communications technology and requirements are necessary and PJM should pursue them immediately.

Along with changes to the communications and deployment process, PJM and the MMU have worked with generators to identify circumstances where reserves were not accurately measured based on the energy and reserve offer parameters. More broadly, the MMU's proposal is to buy the correct amount of reserves. No increase in demand is required. There has been no change in the need/demand for reserves. PJM ignored the supply side. The issue is that resources have not provided the reserves that were offered and paid for. With improved communications technology, instead of buying more MW of poorly performing reserves, PJM will be able to accurately recognize the actual supply of reserves and to more efficiently deploy them in synchronized reserve events. PJM should immediately remove the 30 percent increase to the synchronized reserve reliability requirement in place from May 2023 through September 2025.

The design of the current PJM Regulation Market is significantly flawed.[35] The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. The current market design allows regulation units that have the capability to provide both RegA and RegD MW to submit an offer for both signal types in the same market hour. However, the method of clearing the regulation market for an hour in which one or more units has a dual offer incorrectly accounts for the amount of RegD and the effective MW of the RegD that it clears. The result of the flaw is that the MBF in the clearing phase is incorrectly low compared to the MBF in the solution phase and the actual amount of effective MW procured is higher than the regulation requirement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. Under the current design, slower response RegA resources (generating units) must provide additional regulation to offset the negative impact of RegD resources (largely batteries) that are charging in the middle of a regulation hour. The ability of some resources to submit offers for both RegA and RegD (dual offers) results in inefficient high prices. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

PJM filed significant changes to the regulation market design on April 16, 2024, that were accepted as filed by order of June 17, 2024.[36] PJM will implement the changes to the regulation market in two phases. Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The proposed Phase 1 changes will eliminate many of the significant issues identified by the MMU that have resulted from a two product, two signal market design including the incorrect and inconsistent use and application of the MBF/MRTS.

The benefits of markets can be realized under the current approach to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power. However, there are significant issues with the PJM ancillary services markets.

The MMU concludes that the synchronized reserve market results were not competitive. The MMU concludes that the nonsynchronized reserve market results were not competitive. The MMU concludes that the secondary reserve market results were competitive. The MMU concludes that the regulation market results were not competitive, and the market design is significantly flawed.

35 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

36 PJM, "Regulation Market Design Filing," Docket No. ER24-1772-000 (April 16, 2024).

PJM Reserve Markets

Reserves resources are scheduled and paid for the availability to respond to a loss of supply on the system by increasing their energy output within defined time limits. When a resource clears in a reserve market, it is assigned scheduled reserve MW by that reserve market. Most reserve MW are cleared by the reserve markets, but PJM has the ability to schedule resources outside of the markets when needed.

PJM clears reserves to satisfy defined reserve service requirements. There are three reserve services: the synchronized reserve service (SR), the primary reserve service (PR), and the 30-minute reserve service (TMR). Each reserve service is defined by its response time requirement and by whether the service can be provided by offline resources (Table 10-5). Only the synchronized reserve service requires that all providers be online and synchronized to the grid. The other two services, primary reserve and 30-minute reserve, can be provided by both online and offline resources.

Table 10-5 Reserve services and their definitions

Service	Response Requirement (minutes)	Provided by Online Resources	Provided by Offline Resources
Synchronized Reserve	10 or less	Yes	No
Primary Reserve	10 or less	Yes	Yes
30-Minute Reserve	30 or less	Yes	Yes

Each reserve service requires a specified number of MW to be available in order to cover a potential loss of supply event, known as that service's reserve requirement. The size of a service's requirement depends on the contingencies that the service is designed to address (determining the service's reliability requirement), plus the option to add a requirement to account for potential demand increases due to temporary conditions like emergencies and weather alerts (determining the extended requirement). A service's total requirement is equal to the sum of its reliability requirement, which is unique to each service, plus the extended reserve requirement, which is the same for all services and has a base value of 190 MW.[37] [38] The default extended reserve requirement of 190 MW was designed to phase in the price impacts of shortage pricing in real time.

The reserve services are nested, such that the satisfaction of the synchronized reserve requirement counts towards the satisfaction of the primary reserve requirement, which counts towards the satisfaction of the 30-minute reserve requirement. The principal contingency for which reserves are cleared is the loss, in a single event, of the largest generator or group of generators, known as the "most severe single contingency," or the MSSC. Therefore, the reliability requirement of each service, in whole or in part, depends upon the size of the MSSC. Table 10-6 shows the default definitions of the reliability requirements and the full requirements. For calculating the 30-minute reserve requirement, PJM uses a pre-defined set of additional contingencies to simulate the effects of gas infrastructure failures on gas generators.[39] The use of these special contingencies is communicated to generators via PJM Emergency Procedures under "Gas Pipeline Emergencies".[40]

PJM selectively calls upon reserve services to respond to events. For example, to engage synchronized reserves, PJM initiates a synchronized reserve event, also called a spinning event.[41] In the first nine months of 2025, PJM did not call on nonsynchronized reserves to collectively respond to a reserve event. PJM calls on some nonsynchronized resources to individually respond during synchronized reserve events.

The deployment of 10-minute reserves can also be in response to dispatches from the New York Independent System Operator (NYISO), which serves as the dispatcher for shared reserve activation.[42] [43] Members of the PJM Mid-Atlantic Control Zone have agreed to activate a portion of 10-minute reserve

37 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 134 (Apr. 23, 2025).
38 PJM has proposed creating individual extended requirements for each reserve service. This proposal was approved by the Reserve Certainty Senior Task Force on June 6, 2024, but was rejected by the Markets & Reliability Committee on July 24, 2024.
39 See PJM. "PJM Manual 13: Emergency Operations," § 3.9 Assessing Gas Infrastructure Contingency Impacts on the Electric System, Rev. 95 (Feb. 20, 2025).
40 PJM. Emergency Procedures – Message Definitions. (2025) <https://emergencyprocedures.pjm.com/ep/pages/messagedefinitions.jsf> Mar. 3, 2025.
41 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 55 (Jun. 18, 2025).
42 See PJM. "PJM Manual 12: Balancing Operations," § 4.2 Shared Reserves, Rev. 55 (Jun. 18, 2025).
43 See NPCC. "NPCC Regional Reliability Directory #5: Reserve," Attachment B - Simultaneous Activation of Ten-Minute Reserve (SAR) Contingencies, Rev. 5 (Apr. 20, 2020).

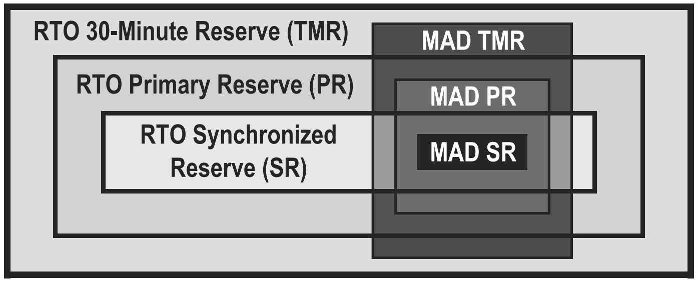
in coordination with members of the Northeast Power Coordinating Council when directed in order to relieve stress on the interconnected grid.

During an event, reserves respond either by increasing their energy output to the grid or by decreasing their energy consumption from the grid. The delivery of this energy is constrained by transmission limits, such that there are also limited locational requirements for each of the reserve services, except for the 30-minute reserve service.[44] PJM uses these constraints to define a reserve subzone with its own smaller requirements for synchronized reserve and primary reserve. Reserves in the subzone count towards the satisfaction of the requirements for the entire RTO Reserve Zone.[45] For example, satisfaction of the synchronized reserve requirement in the Mid-Atlantic Dominion (MAD) Reserve Subzone also counts towards the primary reserve requirement in the MAD Subzone and the synchronized reserve requirement in the RTO Zone, which in turn counts towards the satisfaction of the primary reserve requirement in the RTO Zone. There is only one active reserve subzone at a time. Figure 10-1 shows how reserve requirements for the MAD Reserve Subzone are nested inside the RTO Reserve Zone when the MAD Subzone is the active subzone.

Table 10-6 Service requirement definitions[46]

Service	Service Reliability Requirement	Service Extended Requirement
Synchronized Reserve (SR)	Most Severe Single Contingency	SR Reliability Requirement + Extended Reserve Requirement
Primary Reserve (PR)	1.5 × SR Reliability Requirement	PR Reliability Requirement + Extended Reserve Requirement
30-Minute Reserve (TMR)	Max(Largest Active Gas Contingency, PR Reliability Requirement, 3,000 MW)	TMR Reliability Requirement + Extended Reserve Requirement

Figure 10-1 Service nesting in the RTO Reserve Zone and the Mid-Atlantic Dominion (MAD) Reserve Subzone



In May 2023, PJM made two unilateral changes in succession to the reserve requirements to compensate for the asserted lack of performance during spin events. Table 10-21 shows the average performance for events 10 or more minutes long. The average response to the two events of 10 minutes or more that occurred in the first four months of 2023, both in January, was 56.9 percent, compared to 50.3 percent in the last three months of 2022. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the MSSC. Figure 10-17 compares the changes in demand. PJM will decrease or increase the adder based on the average performance across non-overlapping sets of three 10-minute events.[47]

The reserve requirements effective for a scheduling interval can change from interval to interval depending on the contingencies and needs of the grid. When maintenance work at a power station risks tripping multiple generators whose total output is larger than the MSSC, PJM can increase the requirement for synchronized reserve to include that total output. PJM can increase the reserve requirement due to emergencies and weather alerts. In May 2023, PJM unilaterally modified *PJM Manual 11: Energy & Ancillary Services*

44 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.1 Locational Aspect of Reserves, Rev. 134 (Apr. 23, 2025).
45 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 134 (Apr. 23, 2025).
46 From mid-May 2023 through September 2025, PJM has set the synchronized reserve reliability requirement to be 130 percent of the MSSC. See "Synchronized Reserve Requirement for Reliability – Update," (March 6, 2025). <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.
47 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

Market Operations to allow PJM to temporarily increase the requirements to compensate for poor resource performance in order to continue compliance with ReliabilityFirst's regional criteria.[48] [49] Table 10-7 shows the instances identified by the MMU when PJM temporarily increased the reserve requirements in the first nine months of 2025.

Table 10-7 Temporary adjustments to 30-minute, primary, and synchronized reserve requirements: January through September, 2025[50]

From	To	Number of Hours	Amount of Adjustment
19-May-23	Ongoing	18,576+	30 percent increase to synchronized reserve reliability requirement
8-Jan-25	10-Jan-25	72	30-Minute Reserve (127 MW), Primary Reserve (245 MW), Synchronized Reserve (163 MW)
14-Jan-25	16-Jan-25	52	30-Minute Reserve (0 MW), Primary Reserve (0 MW), Synchronized Reserve (0 MW)
20-Jan-25	24-Jan-25	95	30-Minute Reserve (246 MW), Primary Reserve (420 MW), Synchronized Reserve (280 MW)
17-Feb-25	20-Feb-25	72	30-Minute Reserve (0 MW), Primary Reserve (28 MW), Synchronized Reserve (18 MW)
16-Mar-25	20-Mar-25	101	30-Minute Reserve (0 MW), Primary Reserve (0 MW), Synchronized Reserve (0 MW)

PJM must comply with the reserve requirements imposed by NERC, but PJM uses requirements that are more restrictive than NERC requirements. NERC Performance Standard BAL-002-3, which describes NERC's Disturbance Control Standard (DCS), defines a requirement for contingency reserve, which PJM implements as primary reserve.[51] [52] NERC BAL-002-3 does not define requirements specifically for synchronized reserve or for 30-minute reserve. NERC requires that contingency reserves respond within 15 minutes, while PJM requires that primary reserves respond within 10 minutes. NERC requires that PJM have contingency reserves greater than or equal to the MSSC, while PJM has historically targeted procuring primary reserve equal to at least 150 percent of the MSSC and procuring synchronized reserve equal to at least 100 percent of the MSSC. With PJM's 30-percent increase to the synchronized reserve reliability requirement (Table 10-7), PJM currently targets procuring primary reserve in excess of 195 percent of the MSSC and procuring synchronized reserve in excess of 130 percent of the MSSC.

A NERC DCS event is defined as the loss of supply, in a single event, of 80 percent or more of the MSSC. The event begins as soon as the Reporting ACE (a version of the area control error) starts to drop and ends when the Reporting ACE returns to the lesser of zero and its value at the start of the event. Although PJM uses synchronized reserve events to recover from DCS events, synchronized reserve events are generally longer than their corresponding DCS events (Table 10-23).

There are three kinds of resources that can provide reserves: online generators that can increase their energy output, offline generators that can start and provide their energy output, and demand response resources that can decrease their energy use. From these resources, there are three reserve products: synchronized reserves (SR), nonsynchronized reserves (NSR), and secondary reserves (SecR).[53] A reserve product is defined by its response-time requirement and by the types of resources that can provide it (Table 10-8).

Table 10-8 Reserve products and definitions

Reserve Product	Response Requirement (minutes)	Provided by Online Generators	Provided by Offline Generators	Provided by Demand-Side Response
Synchronized Reserve	10 or less	Yes	No	Yes
Nonsynchronized Reserve	10 or less	No	Yes	No
Secondary Reserve	10 exclusive to 30 exclusive	Yes	Yes	Yes

A reserve product can only be used to satisfy a reserve service's scheduling requirement if it also satisfies that service's response-time requirement and synchronization requirement, which are listed in Table 10-5. Table 10-9 shows which reserve products can be used to satisfy which reserve services.

48 RFC_Criteria_BAL-002-02. "Operating Reserves," August 29, 2012. <https://rfirst.org/ProgramAreas/Standards/Criteria/Regional%20Criteria%20Library/RFC_Criteria_BAL-002-02.pdf>.
49 See *id*, which describes the document as a "ReliabilityFirst Board of Directors approved good utility practice document which are not reliability standards" and notes that "ReliabilityFirst Regional Criteria are not NERC reliability standards, regional reliability standards, or regional variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval."
50 PJM does not make public the exact increases in reserves nor the exact times increases are used. This table shows the differences between the average reserve values inside times that have been identified for possible increases in reserves with the average values before and after those times. The ranges given can include several overlapping timespans of possible increases.
51 NERC BAL-002-3. "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," April 1, 2019. <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.
52 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead and Real-Time Reserves, Rev. 45 (Nov. 21, 2024).
53 OATT, Attachment K - Appendix § 1.7.19 (Ramping).

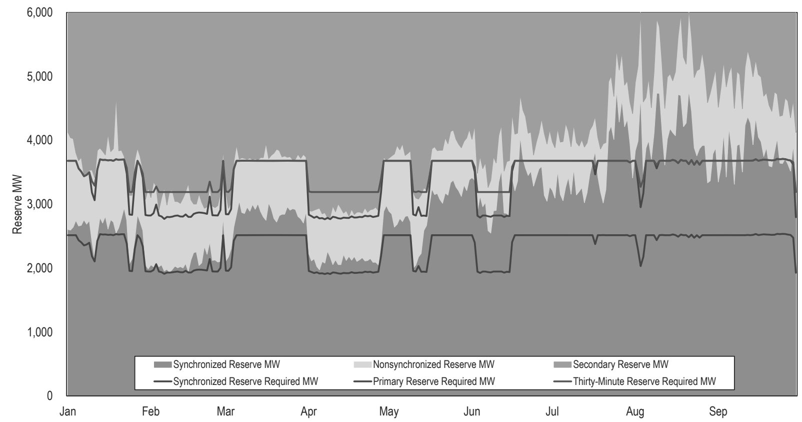
Table 10-9 Reserve products and the services they can provide

Reserve Product	Can Provide Synchronized Reserve	Can Provide Primary Reserve	Can Provide 30-Minute Reserve
Synchronized Reserve	Yes	Yes	Yes
Nonsynchronized Reserve	No	Yes	Yes
Secondary Reserve	No	No	Yes

Figure 10-2 shows how reserve products were cleared in real time to meet the reserve service requirements in the first nine months of 2025. In the figure, each line represents the extended requirement of a reserve service, which is the service's reliability requirement plus the generic extended requirement. The colored areas represent how the cleared MW of the three reserve products combine to satisfy the reserve requirements. As can be seen in the figure, the cleared reserve products providing the services do not exactly equal the service requirements. In the first nine months of 2025, the total amounts of cleared synchronized reserve and 30-minute reserve were frequently greater than their requirements. This can result from cleared resources providing more reserves than needed to satisfy the remainder of a requirement and can result from PJM clearing reserve products to help satisfy the requirements of the next broader reserve service. For example, in January, PJM cleared synchronized reserves in excess of the synchronized reserve requirement in order to, along with the cleared nonsynchronized reserve, more economically satisfy the primary reserve requirement.

Although not seen in Figure 10-2, PJM does not always clear enough reserves to satisfy a reserve requirement. When a service's requirement is not met, the result is shortage pricing.

Figure 10-2 Daily average real-time reserve products cleared and daily average real-time reserve service requirements used by RT SCED: January through September, 2025



PJM uses market mechanisms to clear resources. In general, products that meet shorter response time requirements and that can be used to satisfy multiple reserve requirements have higher prices. The objective is to minimize total cost when purchasing reserves and energy.

Implementation of PJM Reserve Markets

While the primary reserve requirement and 30-minute reserve requirement can be satisfied using multiple products, the products are purchased separately. There are separate markets for synchronized reserves, nonsynchronized reserves, and secondary reserves.[54] MW that are selected as reserve are said to have cleared the market. Effective October 1, 2022, each product's reserve market has a day-ahead component and a real-time component. The obligations of a reserve resource depend on its real-time assignment, which in turn depends on how the resource clears the day-ahead and real-time markets. A resource that cleared one market is not guaranteed to have cleared the other market, and a resource that cleared both markets need not clear the

54 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 134 (Apr. 23, 2025).

same amount in real time as it did day ahead. Although multiple reserve products can be used to satisfy the same reserve service requirements, the reserve products are not necessarily paid the same market clearing prices. Each market for a reserve product has a single market clearing price that is applied to all reserve MW cleared in that market, regardless of the service that required the clearing of those MW.

In general, the reserve MW available from a resource are calculated by PJM based on the parameters in the resource's energy offer and reserve parameters. Some resource types, such as hydroelectric resources, energy storage resources, and demand response resources, can specify reserve offer amounts.[55] Generation capacity resources are required to participate in the reserve markets. However, nuclear, solar, and wind resources are excluded by default and must request inclusion in the reserve markets. PJM can automatically deselect a resource from participating in the reserve market for performance reasons.[56] [57] PJM can temporarily deselect a resource from providing reserves for, among other reasons, failing to reliably follow PJM's dispatch signal. A resource that is deselected for failing to follow PJM's dispatch signal is in violation of its must-offer requirement.[58]

A generation resource can request a maximum MW value for its reserve offer (synchronized, secondary, or both individually) that is lower than its economic maximum if that generator's reserve offer is subject to a physical limitation that cannot be modeled by a segmented hourly ramp rate.[59] Such a request must include documentation and data demonstrating the limitation. Both PJM and the MMU review the request. PJM must respond within 30 days after data supporting the request is submitted, telling the generation owner whether the request was accepted or denied, and if denied, for what reason.

The clearing of resources to meet PJM's operational requirements includes multiple steps to commit resources, dispatch resources, and calculate clearing prices.[60] [61] Each program in the commitment and dispatching process estimates future needs. The day-ahead market solution software schedules resources in one-hour blocks.[62] The real-time software schedules resources in five-minute intervals.

Due to their start and notification times, some resources can only be cleared in the earlier steps of PJM's commitment and dispatching process. Depending on their physical run-time requirements, resources are described as either flexible or inflexible. Inflexible resources are those that must run for at least one hour and are only committed in real-time by the hour-ahead real-time software or by a PJM operator, and can include demand response resources, offline CTs and hydro resources that can operate in condensing mode, and resources whose economic minimum output equals their economic maximum output. Flexible resources are those that can be cleared for reserves by RT SCED later in the process. Such resources are already online for energy, require no notification time, and can be automatically dispatched.

In general, resources do not have to clear the same amounts in the real-time and day-ahead markets, and a resource that cleared one of the markets is not guaranteed to have cleared the other. However, if an inflexible condenser or an inflexible economic load response resource has a day-ahead assignment, that assignment is also applied to the operating day.[63]

Not all resources that provide reserves necessarily clear the reserve market. When needed, PJM is able to manually schedule a resource for reserves if that resource would not have otherwise run.[64] Similarly, not all inflexible reserve resources cleared by the ASO and IT SCED are necessarily used for reserves. When needed, PJM can manually switch inflexible resources from providing reserves to providing energy.

55 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 134 (Apr. 23, 2025).
56 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 134 (Apr. 23, 2025).
57 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 134 (Apr. 23, 2025).
58 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 134 (Apr. 23, 2025).
59 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 134 (Apr. 23, 2025).
60 For more on the market solution software, see the *2024 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.
61 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 5.2 Scheduling Tools, Rev. 134 (Apr. 23, 2025).
62 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.2 Day-ahead Reserve Market Clearing, Rev. 134 (Apr. 23, 2025).
63 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Real-time Reserve Market Clearing, Rev. 134 (Apr. 23, 2025).
64 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Real-time Reserve Market Clearing, Rev. 134 (Apr. 23, 2025).

Figure 10-4 compares the daily average requirements of the day-ahead clearing engine, the ASO, and RT SCED. Figure 10-4 shows that the reserve requirements used by the ASO and RT SCED do not differ significantly. Until May 12, 2023, the daily average 30-minute reserve requirement was almost always 3,190 MW in the day-ahead, ASO, and RT SCED (Figure 10-4).

Figure 10-3 compares the daily average cleared MW of the day-ahead clearing engine, the ASO, and RT SCED. In addition to the increase in cleared secondary reserve resulting from PJM correcting its software error, Figure 10-3 shows that the day-ahead market also tended to clear the most nonsynchronized reserve. For satisfying the primary reserve requirement, the ASO uses more synchronized reserves, clearing less nonsynchronized reserves than RT SCED due to differences in the available MW that result from differences in the applied unit schedules. This difference is also seen in Figure 10-23.

Figure 10-3 MW cleared by the day-ahead engine, the ASO, and RT SCED: January through September, 2025

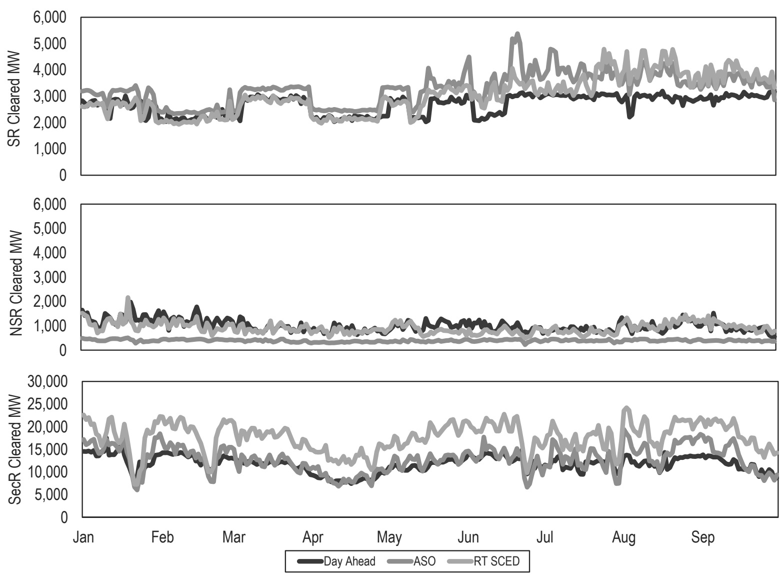
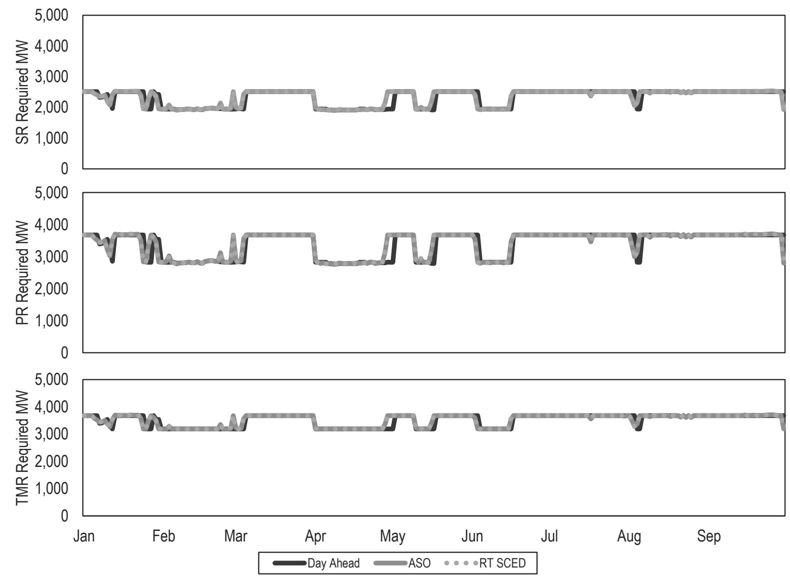


Figure 10-4 Requirements used in the day-ahead engine, the ASO, and RT SCED: January through September, 2025

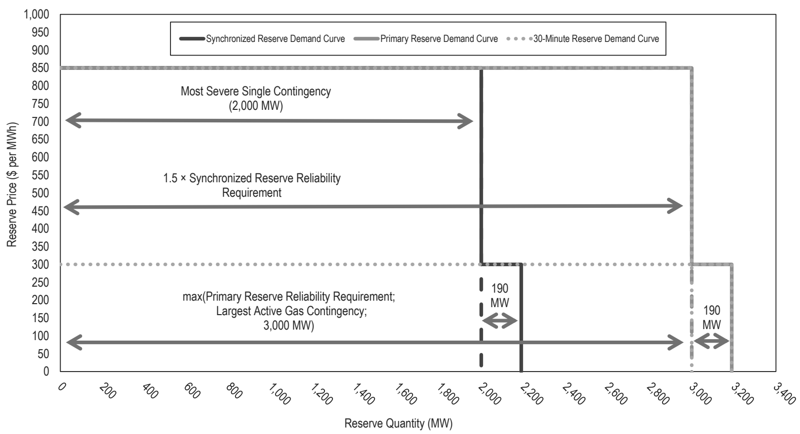


There is a defined MW demand only for synchronized reserves, primary reserves, and 30-minute reserves. The demand for nonsynchronized reserves and for secondary reserves is derived from those defined MW demand levels and cleared supply. PJM's administratively defined demand curve for reserves is called the Operating Reserve Demand Curve (ORDC) and has two steps. The first step of each reserve product's ORDC is set at that product's reliability requirement and is priced at $850 per MWh. The second step is the extended reserve requirement and is priced at $300 per MWh. Figure 10-5 shows example ORDCs for the three reserve products using an example MSSC of 1,000 MW with no increases in the extended reserve requirement.

In 2014, PJM added an optional second step to the ORDC, which could be increased from its default value of 0 MW to account for increased uncertainty identified by PJM. In 2017, PJM proposed a minimum value of 190 MW for the then optional second step, bringing it to its current form.[65] [66]

Figure 10-5 shows an example of the three operating reserve demand curves for each reserve product for an example MSSC at 1,000 MW with no increases in the extended reserve requirement. The adjusted ORDCs resulting from PJM's increase to the synchronized reserve reliability requirement are shown in Figure 10-18.

Figure 10-5 An example of the reserve product real-time operating reserve demand curves, including the permanent second steps



During periods of shortage pricing, the reserve market clearing prices can be higher than the limits shown in Figure 10-5. Offer prices for synchronized reserve are cost based and are capped at the expected value of the synchronized reserve penalty. The product substitution cost is a function of LMPs, the marginal cost of energy for the resources providing reserves, and the minimized cost of substituted MW providing energy. At the margin, the price is the sum of the offer price and the product substitution cost of the marginal unit(s).[67]

Like the markets, credits and charges for reserves have day-ahead and real-time components. Day-ahead credits depend only on a resource's day-ahead assignment and the day-ahead market clearing price. There are no lost opportunity cost (LOC) credits in the day-ahead market, nor are there any shortfall charges applied to day-ahead assignments when evaluating resource performance. These concepts apply only to the real-time reserve markets.

The real-time component, known as the balancing credit, is added to day-ahead credits based on the difference between the real-time and day-ahead assignments. This balancing credit for a resource is the sum of a resource's balancing MCP credit and LOC credit, less any shortfall charge for failing to provide the service. If a resource clears less MW in real-time than in the day-ahead market, and if it is found to be at fault for this reduction, then the balancing MCP credit is negative and so the resource buys back this difference at real-time prices. If the resource clears more in real time, then it is positive. If a resource's real-time assignment is the same as its day-ahead assignment, then the balancing MCP credit is $0 and the resource's total MCP credit uses only the day-ahead MCP.

For the synchronized reserve product and the secondary reserve product, the MW for which a resource receives real-time credit can be capped at a value less than the cleared real-time amount. Without capping, a reserve resource producing energy above its directed amount would be paid for reserve MW that it did not actually make available.

Reserve Subzones

Reserve subzones address transmission limits that may prevent the lowest cost reserves from being deliverable throughout the RTO. A reserve subzone has its own reserve requirements, which can only be satisfied by resources within the subzone. The RTO Reserve Zone has only one active subzone at any time. In practice, PJM has maintained only one subzone, the Mid-Atlantic

65 See the transmittal letter to Revisions to OA Schedule 1 and OATT Att K-Appx RE Operating Reserve Demand Curve, Docket No. ER17-1590-000 (May 12, 2017) at 8.
66 For background data, see "Shortage Pricing ORDC - Order 825," PJM presentation to the Market Implementation Committee. (October 26, 2016) <https://www.pjm.com/-/media/committees-groups/committees/mic/20161026-special/20161026-item-03-shortage-ordc.ashx>
67 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.9 Synchronized Reserve Market Clearing Price (SRMCP) Calculation, Rev. 121 (July 7, 2022). This version of the manual has a clearer definition than later versions.

Dominion Reserve Subzone (MAD), and in every market solution, the most limiting constraining path sets the transfer limit between the RTO and in MAD. The price in MAD may exceed the price in the rest of the RTO when the constraints are binding.

While PJM generally triggers synchronized reserve events for the entire RTO, PJM has the option to only load reserves in the defined subzone. For example, on February 24, 2024, PJM initiated a synchronized reserve event only for MAD.

The choice of MAD was a result of historical congestion patterns. Transmission limits at times required maintaining out of merit reserves in the MAD area. On most days, the MAD Subzone is no longer binding. As of October 1, 2022, PJM has a process to revise the definition of the subzone. The subzone definition may change as often as daily based on system conditions, and new subzones can be defined as needed.[68] In 2024 and the first nine months of 2025, PJM did not change the subzone.

Figure 10-6 is a map of constraints and major generation sources, showing how the constraints separating the RTO Reserve Zone and MAD Reserve Subzone are defined by the underlying grid topology. The most frequently binding constraints in the first nine months of 2025 were Bedington-Black Oak, Brighton-Conastone, and Cloverdale-Lexington.

Figure 10-7 shows the reserve service requirements and cleared reserve product in the MAD Reserve Subzone in the first nine months of 2025. As there is no 30-minute reserve requirement for the MAD Reserve Subzone, secondary reserve is excluded. The increase in reserve requirements in effect since mid-May 2023 does not apply to the MAD Reserve Subzone, only to the RTO Reserve Zone.

68 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.2 Creation of New Reserve Subzones, Rev. 134 (Apr. 23, 2025).

Figure 10-6 PJM RTO Zone and MAD Subzone map of constraints and generation sources

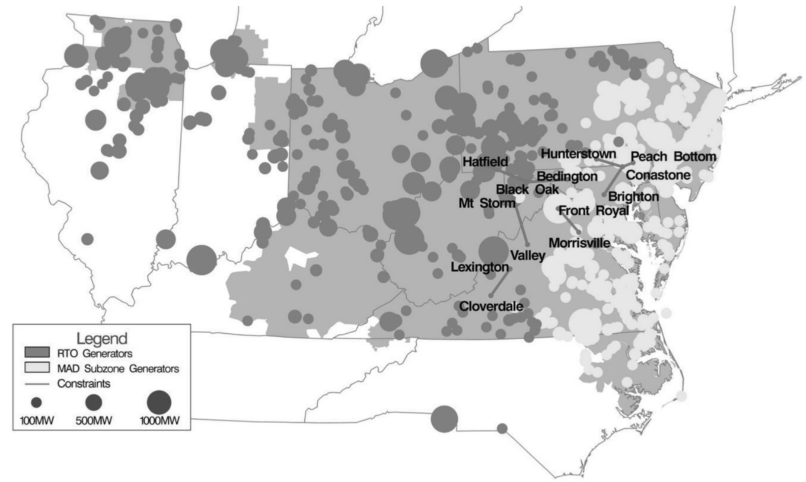
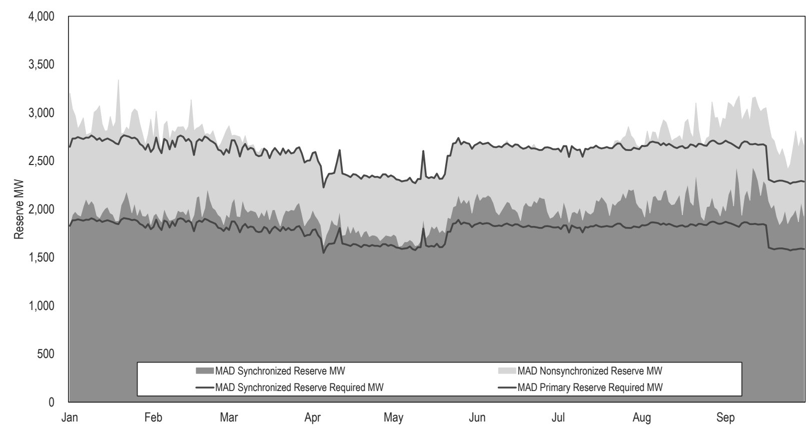


Figure 10-7 Daily average real-time MAD reserve products and daily average real-time MAD reserve service requirements: January through September, 2025



Primary Reserve

NERC Performance Standard BAL-002-3, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, requires PJM to carry sufficient contingency reserve to recover from a sudden balancing contingency (usually a loss of generation). The Contingency Event Recovery Period is the time required to return the Reporting ACE to the lesser of zero and its pre-event level. The Contingency Reserve Restoration period is the time required to restore contingency (primary) reserves to a level greater than or equal to the largest single contingency after the end of the Contingency Event Recovery Period. NERC standards set the Contingency Event Recovery Period as 15 minutes and the Contingency Reserve Restoration Period as 90 minutes.[69] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve recovery period requirement using primary reserves.[70] PJM maintains 10-minute reserves (primary reserves) which is more conservative than the NERC requirement. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. PJM does not have a Contingency Reserve Restoration Period standard.

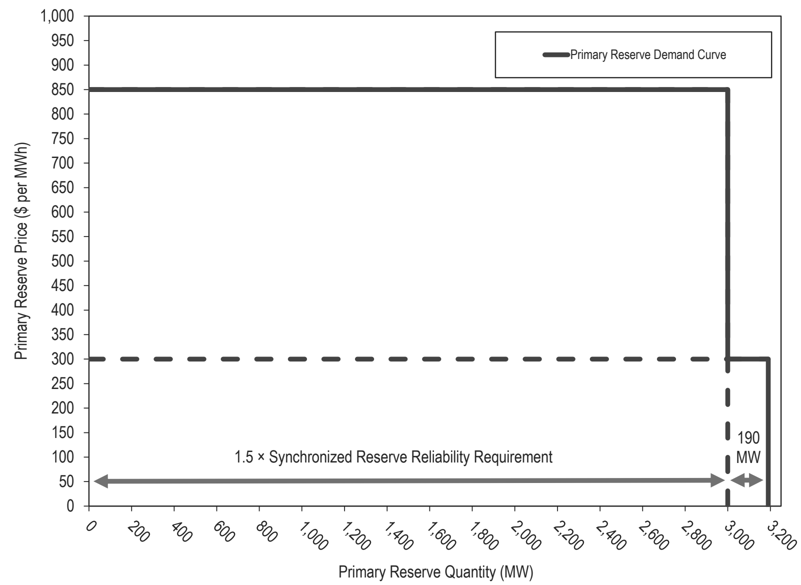
Market Structure

Demand

Demand for primary reserves is based on the primary reserve requirement. The primary reserve requirement is equal to the sum of the primary reserve reliability requirement, unique to the primary reserve service, plus the extended reserve requirement, which is the same for all services. The primary reserve reliability requirement is equal to 150 percent of the synchronized reserve reliability requirement. Figure 10-8 shows an example operating reserve demand curve for primary reserve for an example synchronized reserve reliability requirement of 2,000 MW plus the default 190 MW extension.

69 See PJM. "PJM Manual 12: Balancing Operations," Rev. 55 (Jun. 18, 2025) Attachment D, "the Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes." While this cited attachment only references restoring synchronized reserves, PJM Manuals 10 & 13 make it clear that primary reserves serve as PJM's contingency reserves, although PJM generally uses synchronized reserves to recover from contingency events.
70 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1 Reserve Definitions, Rev. 45 (Nov. 21, 2024).

Figure 10-8 An example of a primary reserve real-time operating reserve demand curve, including the permanent second step



In the first nine months of 2025, the average primary reserve requirement for the RTO Zone was 3,401.4 MW in the real-time market and 3,384.4 MW in the day-ahead market. The average primary reserve requirement in the MAD Subzone was 2,584.7 MW in the real-time market and 2,559.0 MW in the day-ahead market.

In an attempt to offset poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately made changes to the reserve requirements in May 2023. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the MSSC. In effect, this increased the primary reserve reliability requirement by

45 percentage points to 195 percent of the MSSC. PJM has announced criteria to decrease or increase the adder based on average performance across non-overlapping sets of three 10-minute events.[71]

Supply

In the first nine months of 2025, the demand for primary reserve was satisfied by synchronized reserves and nonsynchronized reserves. The primary reserve requirement is met from the least expensive combination of synchronized and nonsynchronized reserves that satisfies the requirements of the primary reserve service and the synchronized reserve service. Table 10-10 shows the real-time average available MW from synchronized and nonsynchronized resources in the first nine months of 2025.

Table 10-10 Average available MW for clearing: January through September, 2025

Location	Synchronized Reserve MW	Nonsynchronized Reserve MW
RTO	5,763.4	1,006.5
MAD	2,814.0	614.1

Table 10-11 provides the average dispatched reserves, by reserve product, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from January 2024 through September 2025. Table 10-12 shows the average dispatched reserves, by reserve product, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone from January 2024 through September 2025.

Table 10-11 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2024 through September 2025

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2024	Jan	2,007.8	754.0	2,761.8
2024	Feb	1,991.5	707.2	2,698.7
2024	Mar	2,024.3	578.1	2,602.3
2024	Apr	1,724.3	632.6	2,356.9
2024	May	1,968.1	606.3	2,574.4
2024	Jun	1,891.4	782.2	2,673.5
2024	Jul	1,856.2	789.4	2,645.6
2024	Aug	1,906.5	792.3	2,698.7
2024	Sep	1,883.0	839.6	2,722.6
2024	Oct	1,862.0	702.5	2,564.5
2024	Nov	1,685.3	860.2	2,545.5
2024	Dec	1,943.7	896.3	2,840.0
2024	Average	1,830.3	819.7	2,650.0
2025	Jan	1,984.6	924.8	2,909.4
2025	Feb	1,970.7	839.5	2,810.2
2025	Mar	1,966.3	666.9	2,633.2
2025	Apr	1,783.1	598.5	2,381.6
2025	May	1,832.7	618.7	2,451.4
2025	Jun	2,040.1	613.2	2,653.3
2025	Jul	2,038.1	621.3	2,659.4
2025	Aug	2,072.8	738.4	2,811.2
2025	Sep	2,089.3	770.6	2,859.9
2025	Average	1,975.4	709.3	2,684.7

71 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

Table 10-12 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2024 through September 2025

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2024	Jan	2,732.1	950.0	3,682.1
2024	Feb	2,826.8	867.6	3,694.4
2024	Mar	3,006.7	662.7	3,669.4
2024	Apr	2,130.2	753.3	2,883.5
2024	May	2,874.4	674.4	3,548.8
2024	Jun	2,779.6	950.8	3,730.4
2024	Jul	2,584.6	965.0	3,549.6
2024	Aug	2,736.1	929.0	3,665.1
2024	Sep	2,771.0	1,011.1	3,782.2
2024	Oct	2,100.6	792.6	2,893.2
2024	Nov	2,203.0	1,048.5	3,251.5
2024	Dec	2,679.5	1,238.1	3,917.7
2024	Average	2,619.1	903.4	3,522.5
2025	Jan	2,581.5	1,130.2	3,711.8
2025	Feb	2,111.2	1,012.8	3,124.0
2025	Mar	2,801.9	881.5	3,683.4
2025	Apr	2,182.8	776.3	2,959.1
2025	May	2,894.5	863.9	3,758.3
2025	Jun	3,222.9	734.0	3,956.8
2025	Jul	3,580.8	746.6	4,327.4
2025	Aug	4,068.4	1,096.1	5,164.6
2025	Sep	3,814.6	980.6	4,795.2
2025	Average	3,038.4	913.4	3,951.7

Market Concentration

In the first nine months of 2025, the RTO primary reserve market was unconcentrated in day ahead and unconcentrated in real time. In the first nine months of 2025, the MAD primary reserve market was moderately concentrated in day ahead and moderately concentrated in real time. Table 10-13 shows the average of the HHI values of each interval for primary reserves in the first nine months of 2025.

Table 10-13 Average primary reserve HHI: January through September, 2025

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	980	41.2%	Unconcentrated
RTO	DA	915	41.1%	Unconcentrated
MAD	RT	1563	81.4%	Moderately Concentrated
MAD	DA	1401	78.2%	Moderately Concentrated

Market Performance

Figure 10-9 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first nine months of 2025. The synchronized reserve market clearing prices for the RTO Reserve Zone and the MAD Reserve Subzone diverged in 174 intervals, 0.2 percent of the total 78,612 five-minute intervals in the first nine months of 2025. The nonsynchronized reserve market clearing prices for the RTO Reserve Zone and the MAD Reserve Subzone diverged in 172 intervals, 0.2 percent of the total 78,612 five-minute intervals in the first nine months of 2025.

The prices of synchronized reserve and nonsynchronized reserve spiked on January 23, 2025, during the 2025 polar vortex, for which conservative operations were declared and a cold weather alert was issued. Shortage pricing for primary reserve in the RTO was used on February 11, March 12, March 18, and March 19, 2025. Shortage pricing for synchronized reserve for the RTO the MAD Reserve Subzone was used on February 5, 2025. The shortages on February 5 and February 11 occurred during synchronized reserve events. Cold weather alerts were issued for February 17 through February 19. Conservative operations were issued for February 14 and February 16 through February 19. Higher prices in March were due to a decrease in the available nonsynchronized reserve MW, leading PJM to increase the amount of cleared synchronized reserve MW used to satisfy the primary reserve requirement. The prices of synchronized reserve and nonsynchronized spiked on hot weather days in late June, for which conservative operations were declared and hot weather alerts, maximum emergency generation alerts, and a maintenance outage recall were issued. Shortage pricing for primary reserves in the RTO was used on June 22 through June 25, 2025. Shortage pricing for primary reserves in the MAD Reserve Subzone was on June 22 and June 24, 2025.

Shortage pricing for synchronized reserve in the RTO was used on June 22, June 23, June 24, and June 30. Shortage pricing for synchronized reserve in the MAD Reserve Subzone was used on June 24. In July, PJM declared hot weather alerts, maximum emergency generation alerts, and a maintenance outage recall during a second period of hot weather. This second period of hot weather saw 15 intervals of RTO primary reserve shortage pricing. The RTO also used shortage pricing for primary reserves on August 14, August 15, September 1, September 4, and September 25. The MAD Reserve Subzone used shortage pricing for primary reserve on September 4. Shortage pricing for synchronized reserve was used on September 4 in the RTO.

Table 10-14 shows the number of intervals with shortage pricing in which the amount cleared by RT SCED was greater than the reserve requirement absent the increase to the synchronized reserve reliability requirement. In the first nine months of 2025, in the majority of intervals with shortage pricing, RT SCED cleared enough reserve MW to satisfy the original reserve service requirements. These intervals were not short in the sense of failing to clear a sufficient amount of reserves. These intervals were short because of PJM's unilateral increase to the synchronized reserve reliability requirement.

Figure 10-9 Daily average market clearing prices for synchronized reserve and nonsynchronized reserve: January through September, 2025

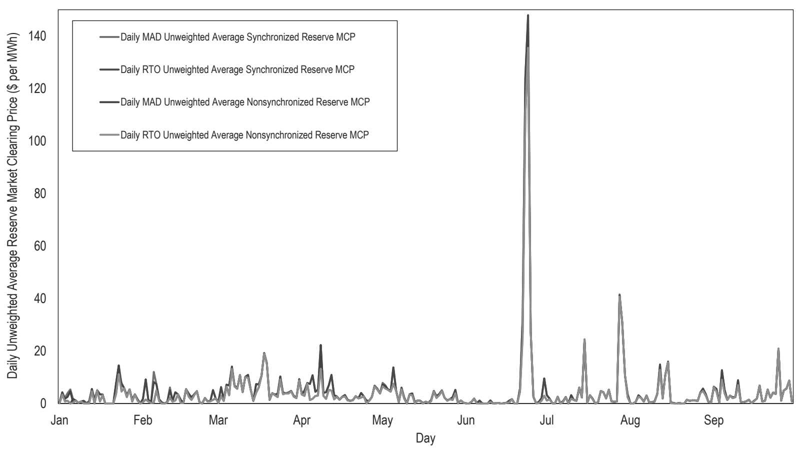


Table 10-14 Number of shortage pricing intervals which satisfied the unmodified reserve service requirement: January through September, 2025

	Intervals with Shortage Pricing			Intervals where RT SCED Satisfied Original Requirement			Percentage of Intervals where RT SCED Satisfied Original Requirement			Intervals where RT SCED Did Not Satisfy Original Requirement		
Location	SR	PR	TMR	SR	PR	TMR	SR	PR	TMR	SR	PR	TMR
RTO	17	111	22	17	79	16	100.0%	71.2%	72.7%	0	32	6
MAD	6	6	0	4	2	0	66.7%	33.3%	NA	2	4	0

Synchronized Reserve

All eligible generation capacity resources capable of providing synchronized reserves have a must offer requirement, and all cleared synchronized reserves have an obligation to perform and receive payment based on the synchronized reserve market clearing price. PJM Manual 11: Energy & Ancillary Services Market Operations states, "Any generator that is a PJM generation capacity resource that has a Reliability Pricing Model (RPM) or Fixed Resource Requirement (FRR) Resource commitment that is eligible to provide Reserves must offer their 10-minute and 30-min reserve capability, unless the unit is unavailable due to an approved planned outage, maintenance outage or forced outage."[72]

Since October 1, 2022, the reserve market design for synchronized reserve includes both day-ahead and real-time markets. Prior to that date, synchronized reserve was only a real-time product.

PJM uses synchronized reserve when PJM calls synchronized reserve events, also called spin events or spinning events.

Market Structure

For most resources, synchronized reserves consist of any online capacity not being used for energy that can be achieved within 10 minutes from the current dispatch point according to the resource's ramp rate. The PJM market solves an economic dispatch to determine which, if any, of these resources should be backed down to provide reserves. Some nondispatchable resources can provide synchronized reserves, including storage resources, hydro resources

72 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Reserve Resource Offer Requirements, Rev. 134 (Apr. 23, 2025).

with storage, synchronous condensers, and demand response resources. For both the RTO and the reserve subzone, the day-ahead market clears hourly synchronized reserve assignments and the real-time market clears five-minute synchronized reserve assignments.

Demand

Demand for the synchronized reserve product comes from the reserve requirement for the synchronized reserve service. The synchronized reserve requirement is equal to the synchronized reserve reliability requirement plus the extended reserve requirement. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Figure 10-5 shows an example operating reserve demand curve for synchronized reserve.

In the first four months of 2023, the synchronized reserve reliability requirement was equal to the MSSC. PJM unilaterally increased the extended reserve requirement by 1,588 MW from May 12, 2023, through May 15, 2023. PJM then unilaterally increased the synchronized reserve reliability requirement to 130 percent of the MSSC on May 19, 2023, which increased the effective primary reserve reliability requirement from 150 percent of the MSSC to 195 percent of the MSSC. Since May 19, 2023, the demand portion has been equal to 130 percent of the MSSC. PJM did not increase demand in the MAD Reserve Subzone, only in the RTO Reserve Zone. Figure 10-17 compares the old and new RTO ORDCs with an example MSSC of 1,000 MW.

Figure 10-2 shows a plot of the daily average real-time requirement for synchronized reserve. In the first nine months of 2025, the average real-time synchronized requirement in the RTO Reserve Zone was 2,330.9 MW and the average day-ahead requirement was 2,319.6 MW. In the MAD Reserve Subzone, the average real-time synchronized requirement was 1,786.4 MW and the average day-ahead requirement was 1,769.4 MW.

Figure 10-16 compares the total amount of cleared synchronized reserve with the subset of cleared synchronized reserve that is provided by DSR. Prior to October 1, 2022, DSR resources were limited by PJM to being no more than 33 percent of cleared synchronized reserves in each interval, but that limitation was removed on October 1, 2022, as part of the changes to the reserve markets.

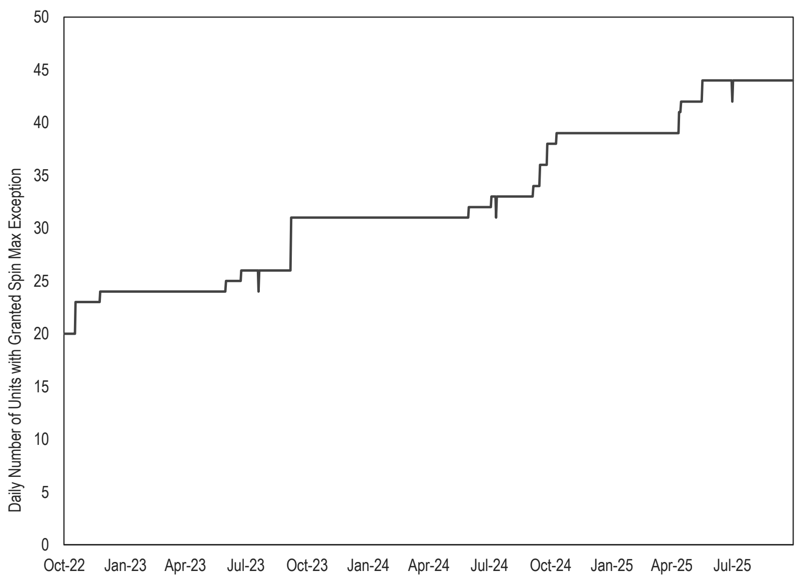
Supply

The supply of synchronized reserves consists of all unloaded capacity that can convert to energy in 10 minutes from eligible online generators and offers from eligible economic load response that can curtail in 10 minutes.[73] Any of this capacity that is not offered as dispatchable in the energy market does not have a lost opportunity cost in the security constrained economic dispatch (SCED). This includes synchronous condensers, storage resources, and demand response. Synchronous condensers and demand response are also considered inflexible in the reserve market and require an hourly commitment, which is made by the Ancillary Services Optimizer (ASO) in real time. This means that these resources enter the SCED reserves supply curve with a marginal cost of zero because PJM is effectively committing them as must run, block loaded reserves.

In general, a resource's reserve MW are the lesser of a resource's 10-minute ramp, and the difference between its energy output and its economic maximum output. A generation resource can request a maximum MW value for its synchronized reserve offer that is lower than its economic maximum if that generator's reserve offer is subject to a physical limitation that cannot be modeled by a segmented hourly ramp rate.[74] Figure 10-10 shows how the number of units that can use a lower synchronized reserve maximum MW has increased. If generators in need of the exception request it, PJM should see improved reserve performance due to a more accurate calculation of the available reserve MW.

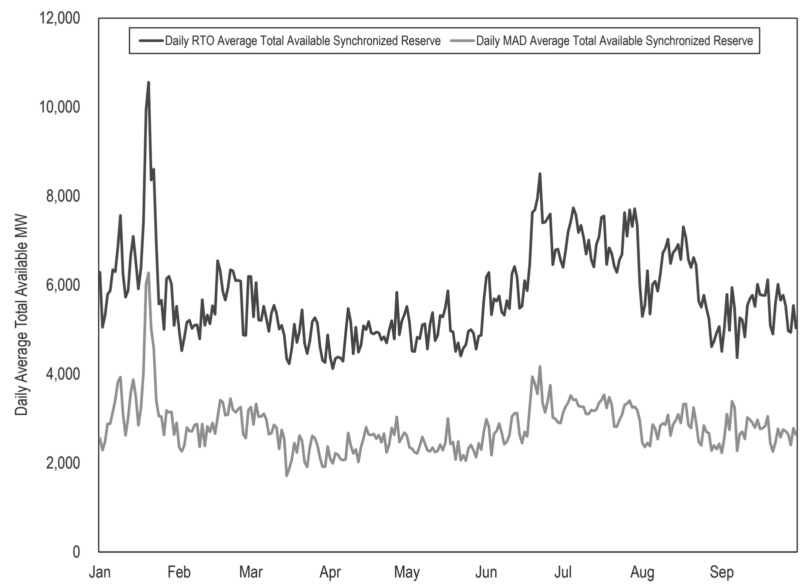
73 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 134 (Apr. 23, 2025).
74 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 134 (Apr. 23, 2025).

Figure 10-10 Number of units per day allowed to use a spin max less than eco max:[75] October 2022 through September 2025



In the first nine months of 2025, the average supply of offered and eligible synchronized reserve was 5,763.4 MW in the RTO Reserve Zone, of which 2,814.0 MW was located in the MAD Reserve Subzone. Figure 10-11 shows the daily average available synchronized reserve MW in the first nine months of 2025. The daily average total available synchronized reserve MW increased in late January due to PJM committing more resources to be online during the 2025 polar vortex. The daily average total available synchronized reserve MW increased in late June due to PJM committing more resources to be online on hot weather days.

Figure 10-11 Daily Average Available Synchronized Reserve: January through September, 2025



Market Concentration

Table 10-15 provides the average HHI and the percent of intervals during which the maximum market share was above 20 percent for the day-ahead and real-time synchronized reserve markets for the first nine months of 2025. In the first nine months of 2025, the MAD synchronized reserve market was moderately concentrated in day ahead and moderately concentrated in real time. In the first nine months of 2025, the RTO synchronized reserve market was unconcentrated in day ahead and unconcentrated in real time.

75 That a unit is able to use a spin maximum less than its economic maximum does not mean that it is required to do so. The count of units that used the exception on a given day can be less than what is shown.

Table 10-15 Day-ahead and real-time synchronized reserve average HHI: January through September, 2025

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	911	34.6%	Unconcentrated
RTO	DA	799	17.9%	Unconcentrated
MAD	RT	1721	88.5%	Moderately Concentrated
MAD	DA	1341	72.7%	Moderately Concentrated

In the first nine months of 2025, the Ancillary Service Optimizer, which schedules economic inflexible resources while considering all resources against forecasted LMPs, failed the three pivotal supplier test in 1,612 hours, 62.0 percent of the 2,602 hours to which the test applied.

Market Behavior

The synchronized reserve offer price must be cost based and is capped at the expected value of the synchronized reserve penalty, which equals the average penalty multiplied by the average rate of nonperformance multiplied by the probability that an event will occur.[76] These values are listed in Figure 10-12. For resources that do not provide an offer price, the offer price is treated as $0 per MWh. In the first nine months of 2025, the weighted average offer price for generators that set their offer MW was $0.001 per MWh. In the first nine months of 2025, the weighted average offer price for DSR resources that set their offer MW was $0.006 per MWh.

Figure 10-12 Expected values of the synchronized reserve penalty: October 2022 through September 2025[77]

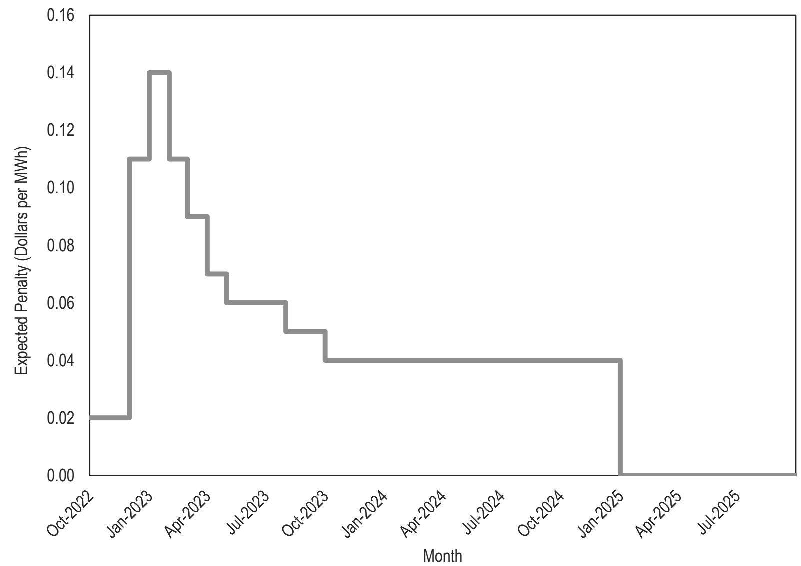
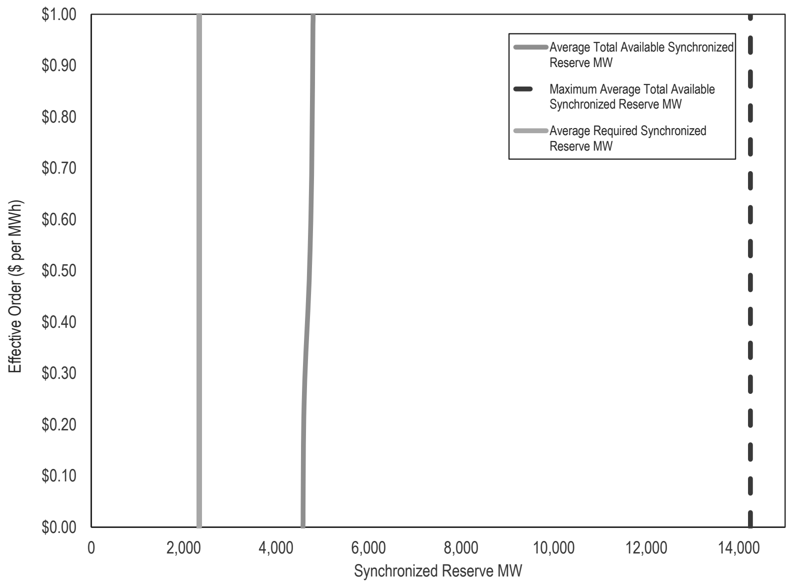


Figure 10-13 shows the average supply of synchronized reserve MW seen by the ASO based on the effective offers for the interval. A generator's effective offer is the sum of the generator's offer price, energy use cost, and the absolute value of the product substitution cost. A DSR resource's effective offer is equal to the offer price. Figure 10-13 also shows the average synchronized reserve requirement across all intervals used by the ASO and the maximum average supply of synchronized reserve MW using all effective offers. As seen in Figure 10-12, the expected value of the synchronized reserve penalty is $0 per MWh, resulting in the shape of the supply curve of the average total synchronized reserve MW.

76 See PJM. "PJM Manual 15: Cost Development Guidelines," § 4.7 Synchronized Reserve, Rev. 46 (Nov. 25, 2024).

77 PJM. *Synchronized Reserve Offer Cap Penalty.* December 3, 2024. <https://www.pjm.com/-/media/markets-ops/ancillary/synchronized-reserve-offer-cap-penalty.ashx>.

Figure 10-13 Average total available MW by effective offer: January through September, 2025



Market Performance

In the first nine months of 2025, the real-time RTO weighted average synchronized reserve market clearing price (SRMCP) was $4.55 per MWh and the day-ahead RTO weighted average SRMCP was $6.23 per MWh. The real-time MAD weighted average SRMCP was $3.94 per MWh and the day-ahead MAD weighted average SRMCP was $6.26 per MWh. In the first nine months of 2025, there were 78,612 five-minute intervals in the real-time market and there were 6,551 hours in the day-ahead market. The real-time RTO SRMCP was $0 per MWh in 67,847 intervals (86.3 percent of all intervals). The real-time MAD SRMCP was $0 per MWh in 67,714 intervals (86.1 percent of all intervals). The day-ahead RTO SRMCP was $0 per MWh in 3,571 hours (54.5 percent of all hours). The day-ahead MAD SRMCP was $0 per MWh in 3,474 hours (53.0 percent of all hours).

Figure 10-14 shows the daily unweighted average prices for synchronized reserve in the real-time and day-ahead markets. Higher day-ahead prices in January occurred during the 2025 polar vortex, for which conservative operations were declared and a cold weather alert was issued. In February, shortage pricing was used on February 5 for the RTO and MAD, and cold weather alerts were issued for February 17 through February 19. Conservative operations were issued for February 14 and February 16 through February 19. Higher average prices in March are due to, as seen in Figure 10-2, a return to a larger synchronized reserve reliability requirement paired with a decrease in the fraction of nonsynchronized reserve cleared. As shown by Figure 10-22, the available nonsynchronized reserve MW decreased in March due to several larger units having planned outages, which necessitated clearing more expensive synchronized reserve resources to satisfy the primary reserve requirement. Real-time prices in late June spiked on hot weather days, for which conservative operations were declared and hot weather alerts, maximum emergency generation alerts, and a maintenance outage recall were issued. On hot weather days in June 2025, the RTO Reserve Zone and the MAD Reserve Subzone used shortage pricing for 79 intervals for one or more of synchronized reserve, primary reserve, and 30-minute reserve. During this hot weather event, two intervals of synchronized reserve shortage pricing were concurrent with a spinning event on June 22, 2025. Higher day-ahead prices for July 27 and July 28 correspond with hot weather alerts and maximum emergency generation alerts. There was no shortage pricing for synchronized reserve on the July hot weather days.

Figure 10-14 Day-ahead and real-time synchronized reserve average market clearing prices: January through September, 2025

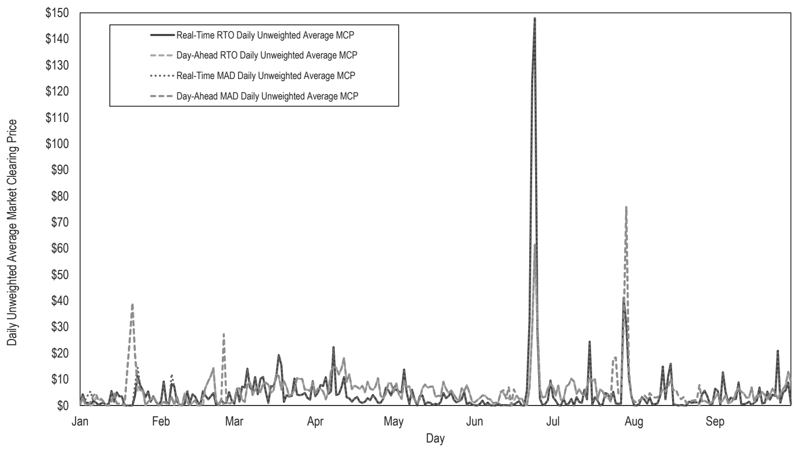


Table 10-16 and Table 10-17 compare the dispatch run and pricing run weighted average prices for the day-ahead and real-time markets. Fast start pricing increases LMP in the pricing run relative to the dispatch run, which increases reserve prices. Fast start pricing also reduces the amount of reserves available in the pricing run compared to the dispatch run, by pretending that fast start units can be dispatched for energy below their economic minimum output limit but not counting MW below the eco min as reserves. For the real-time values, these are the LPC prices weighted using the RT SCED MW. For the day-ahead values, these are the DA prices weighted using the DA dispatch MW. PJM dispatchers can update assignments after RT SCED has run, so these weights differ from the weighted average value reported elsewhere in this section.[78] In the first nine months of 2025, the real-time RTO weighted average price from the pricing run was 37.7 percent higher than the real-time RTO weighted average price from the dispatch run. In the first nine months of 2025, the day-ahead RTO weighted average price from the pricing run was 6.1 percent lower than the day-ahead RTO weighted average price from the dispatch run. In the first nine months of 2025, the real-time MAD weighted average price from the pricing run was 35.8 percent higher than the real-time MAD weighted average price from the dispatch run. In the first nine months of 2025, the day-ahead MAD weighted average price from the pricing run was 5.4 percent lower than the day-ahead MAD weighted average price from the dispatch run.

78 See PJM. "PJM Manual 01: Control Center and Data Exchange Requirements," § 1.7 Dispatch Management Tool (DMT), Rev. 50 (May 21, 2025).

Table 10-16 Day-ahead and real-time fast start pricing in the RTO synchronized reserve market: January 2024 through September 2025

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2024	Jan	$1.69	$1.72	$0.03	1.9%	$1.98	$2.53	$0.55	28.0%
2024	Feb	$1.49	$1.50	$0.00	0.3%	$1.29	$1.82	$0.53	40.9%
2024	Mar	$2.72	$2.74	$0.02	0.8%	$2.69	$3.88	$1.19	44.3%
2024	Apr	$4.14	$4.15	$0.01	0.2%	$0.99	$1.54	$0.55	55.1%
2024	May	$4.29	$4.28	($0.01)	(0.2%)	$3.28	$4.99	$1.72	52.4%
2024	Jun	$2.02	$2.13	$0.11	5.5%	$2.29	$2.56	$0.27	11.8%
2024	Jul	$2.63	$2.80	$0.17	6.3%	$3.00	$3.69	$0.69	23.0%
2024	Aug	$2.33	$2.44	$0.11	4.7%	$2.81	$3.44	$0.62	22.2%
2024	Sep	$2.72	$2.82	$0.11	3.9%	$2.77	$3.73	$0.96	34.8%
2024	Oct	$4.01	$4.10	$0.09	2.1%	$3.62	$4.45	$0.82	22.7%
2024	Nov	$2.13	$2.18	$0.05	2.4%	$1.32	$2.22	$0.90	68.1%
2024	Dec	$0.92	$0.95	$0.03	3.0%	$1.16	$1.64	$0.48	40.9%
2024	All	$2.59	$2.65	$0.06	2.3%	$2.29	$3.08	$0.79	34.2%
2025	Jan	$4.43	$4.79	$0.36	8.0%	$2.02	$2.62	$0.61	30.1%
2025	Feb	$2.56	$2.56	($0.00)	(0.1%)	$1.96	$2.88	$0.92	46.9%
2025	Mar	$7.73	$7.23	($0.50)	(6.5%)	$4.89	$7.28	$2.39	48.9%
2025	Apr	$8.65	$8.48	($0.17)	(2.0%)	$2.64	$4.91	$2.28	86.4%
2025	May	$5.77	$5.45	($0.32)	(5.6%)	$2.15	$3.14	$0.99	45.7%
2025	Jun	$7.96	$7.51	($0.44)	(5.6%)	$9.48	$10.77	$1.29	13.6%
2025	Jul	$10.69	$9.98	($0.70)	(6.6%)	$2.87	$4.67	$1.80	62.8%
2025	Aug	$3.78	$3.22	($0.55)	(14.6%)	$1.24	$2.03	$0.79	63.9%
2025	Sep	$5.66	$4.69	($0.97)	(17.1%)	$2.77	$3.42	$0.65	23.3%
2025	All	$6.46	$6.06	($0.40)	(6.1%)	$3.35	$4.61	$1.26	37.7%

Table 10-17 Day-ahead and real-time fast start pricing in the MAD synchronized reserve market: January 2024 through September 2025

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2024	Jan	$2.63	$2.68	$0.05	1.8%	$3.59	$4.22	$0.63	17.5%
2024	Feb	$1.64	$1.65	$0.00	0.3%	$1.37	$1.89	$0.53	38.4%
2024	Mar	$2.85	$2.87	$0.02	0.7%	$2.69	$3.81	$1.12	41.7%
2024	Apr	$4.37	$4.38	$0.01	0.3%	$0.93	$1.41	$0.48	51.3%
2024	May	$4.19	$4.18	($0.00)	(0.1%)	$3.19	$4.73	$1.54	48.4%
2024	Jun	$2.34	$2.41	$0.07	2.8%	$2.59	$2.83	$0.24	9.1%
2024	Jul	$3.10	$3.30	$0.20	6.5%	$2.81	$3.40	$0.59	21.0%
2024	Aug	$2.43	$2.56	$0.13	5.3%	$3.19	$3.82	$0.63	19.9%
2024	Sep	$2.89	$3.00	$0.11	3.8%	$2.91	$3.95	$1.04	35.8%
2024	Oct	$3.94	$4.02	$0.08	2.0%	$3.73	$4.49	$0.76	20.3%
2024	Nov	$2.20	$2.25	$0.05	2.3%	$1.37	$2.23	$0.86	62.5%
2024	Dec	$2.57	$2.60	$0.03	1.2%	$2.76	$3.28	$0.52	18.9%
2024	All	$2.98	$3.04	$0.06	2.0%	$2.64	$3.41	$0.76	28.8%
2025	Jan	$5.11	$5.53	$0.42	8.2%	$2.15	$2.68	$0.54	25.1%
2025	Feb	$4.02	$4.02	($0.00)	(0.1%)	$1.67	$2.40	$0.73	43.6%
2025	Mar	$8.08	$7.58	($0.49)	(6.1%)	$4.47	$6.65	$2.18	48.9%
2025	Apr	$9.09	$8.92	($0.17)	(1.8%)	$2.41	$4.11	$1.71	70.9%
2025	May	$5.94	$5.60	($0.34)	(5.7%)	$1.92	$2.81	$0.88	45.9%
2025	Jun	$8.17	$7.74	($0.44)	(5.3%)	$7.76	$8.52	$0.77	9.9%
2025	Jul	$10.69	$9.97	($0.72)	(6.7%)	$2.74	$4.37	$1.63	59.7%
2025	Aug	$3.98	$3.46	($0.52)	(13.0%)	$1.16	$1.91	$0.75	64.5%
2025	Sep	$5.42	$4.51	($0.90)	(16.7%)	$2.61	$3.16	$0.55	21.1%
2025	All	$6.62	$6.26	($0.36)	(5.4%)	$2.96	$4.02	$1.06	35.8%

Figure 10-15 shows the dispatch-run synchronized reserve RTO market clearing prices of the day-ahead software (DA), the hour-ahead software (ASO), and the real-time software (RT SCED). The pricing-run market clearing prices, calculated by the LPC, are in Figure 10-14. As seen in Figure 10-15, there can be significant differences in the dispatch-run clearing prices. The ASO schedules units by forecasting least-cost outcomes for the operating hour, and any inflexible resources cleared by the ASO are automatically cleared by RT SCED. Because it is possible for real time to differ from the ASO's forecasts, it is possible for an inflexible resource to be scheduled during real-time conditions in which, had it not been inflexible and already cleared by the ASO, RT SCED would not have scheduled it. For example, it is possible for an inflexible resource to be scheduled in real time even when its bid price is higher than the clearing prices used by RT SCED and the LPC. The opposite can also happen, in which an inflexible resource is not cleared by the ASO while its offer parameters, had it not been inflexible, would have led to it having been cleared by RT SCED.

Figure 10-15 Dispatch run synchronized reserve market clearing prices from the day-ahead software, the ASO, and RT SCED: January through September, 2025

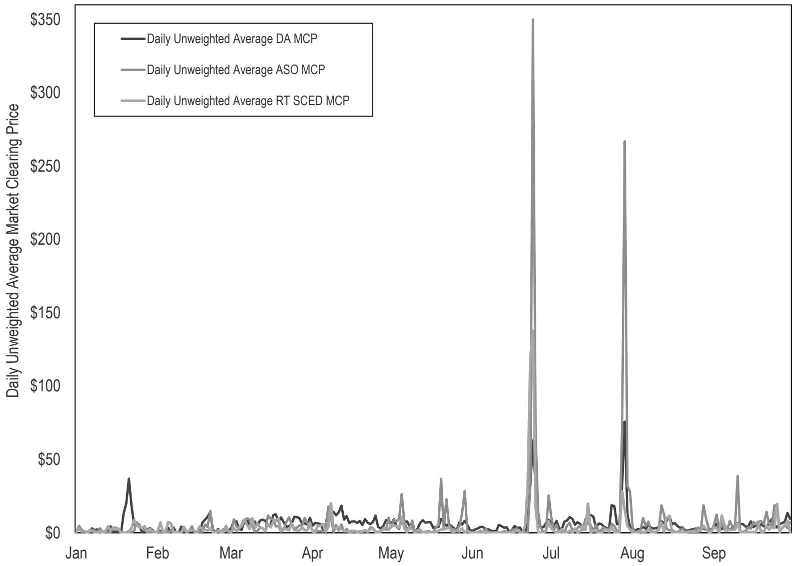


Table 10-18 shows total synchronized reserve payments by month for January 2023 through September 2025. Balancing credits for all but three months are negative, because, on average, resources buy back their day-ahead positions at higher real-time prices. LOC credits are paid to cover negative balancing credits if PJM converted a resource's day-ahead reserve position to energy in the real-time market. LOC credits are also paid to inflexible reserves when prices do not cover their opportunity costs. Shortfall charges are incurred by resources that do not provide their cleared reserve positions in real time. In Table 10-18, the only months with synchronized reserve events that lasted for 10 or more minutes were February 2024, July 2024, August 2024, November 2024, and February 2025, so there are no shortfall charges possible outside of those months. Day-ahead credits were larger in April 2024 and May 2024, corresponding with higher requirements in April and lower supply in May.

Total credits were larger in March 2025 due to a decrease in the available nonsynchronized reserve MW from units on planned outages, necessitating an increase in cleared synchronized reserve MW to meet the primary reserve requirement. Total credits in June 2025 were larger due to price spikes during a hot weather event in which shortage pricing was used for synchronized reserve in the RTO Reserve Zone and the MAD Reserve Subzone. Total credits in July 2025 were larger due to price spikes during a second set hot weather event in which PJM declared hot weather alerts, emergency maximum generation alerts, and a maintenance outage recall. Shortage pricing was not used for synchronized reserve during the July hot weather event.

Table 10-18 Total payments and charges by month: January 2024 through September 2025

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Shortfall Charges	Total Credits
2024	Jan	$4,327,646	($426,107)	$1,136,492	$0	$5,038,031
2024	Feb	$2,894,089	($98)	$535,213	$19,515	$3,409,689
2024	Mar	$5,930,989	($297,375)	$1,078,487	$0	$6,712,102
2024	Apr	$9,018,149	($907,004)	$594,268	$0	$8,705,412
2024	May	$9,477,497	($169,439)	$1,260,078	$0	$10,568,136
2024	Jun	$4,594,840	($602,073)	$788,610	$0	$4,781,377
2024	Jul	$5,994,640	$88,604	$1,400,608	$508,031	$6,975,821
2024	Aug	$5,015,123	($203,403)	$1,001,664	$22,653	$5,790,731
2024	Sep	$5,792,899	($174,272)	$913,489	$0	$6,532,116
2024	Oct	$6,502,979	($238,832)	$1,154,227	$0	$7,418,375
2024	Nov	$3,503,209	$23,756	$600,184	$13,867	$4,113,282
2024	Dec	$3,463,659	($93,407)	$681,863	$0	$4,052,116
2024	All	$66,515,719	($2,999,649)	$11,145,181	$564,066	$74,097,186
2025	Jan	$9,766,427	($93,903)	$1,086,575	$0	$10,759,099
2025	Feb	$5,437,781	($126,526)	$779,549	$118,146	$5,972,657
2025	Mar	$15,181,061	($1,464,818)	$2,047,513	$0	$15,763,757
2025	Apr	$13,256,012	($345,197)	$1,268,522	$0	$14,179,338
2025	May	$10,685,430	($13,743)	$786,811	$0	$11,458,498
2025	Jun	$15,012,782	($4,327,200)	$4,657,608	$0	$15,343,190
2025	Jul	$22,507,389	($310,371)	$2,567,031	$76,684	$24,687,365
2025	Aug	$7,390,714	$20,554	$1,016,281	$0	$8,427,550
2025	Sep	$10,131,551	($840,026)	$1,576,176	$159,581	$10,708,120
2025	All	$109,369,148	($7,501,228)	$15,786,067	$354,411	$117,299,575

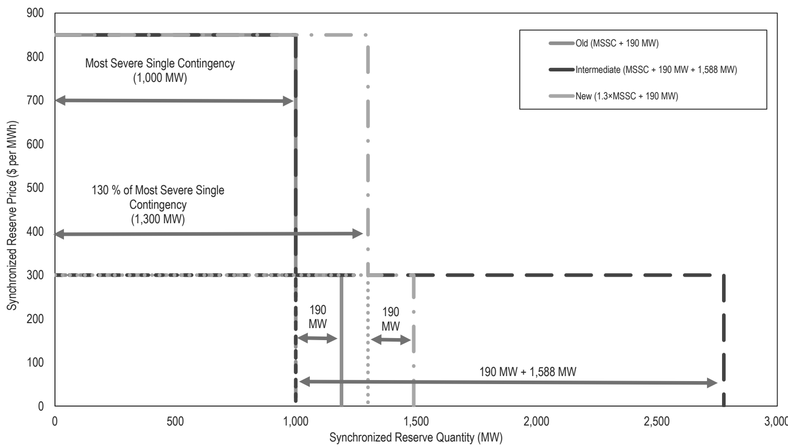
Table 10-19 provides the day-ahead and real-time synchronized reserve by resource type and fuel type for the first nine months of 2025. For synchronized reserve, the MW for which a resource is credited at the market clearing price is capped at the lesser of its real-time assignment and the difference between its real-time output and the lesser of its economic maximum and its real-time reserve maximum. During spin events, this capped value is equal to the cleared MW. As it is this capped value for which a resource is credited, Table 10-19 only shows the capped value, excluding the additional cleared MW.

Table 10-19 Day-ahead and real-time synchronized reserve by resource type and fuel type: January through September, 2025

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
Combined Cycle	8,562,223	7,982,011	$45,202,817	($12,642,911)	$5,716,502	$96,711	$38,179,697
CT - Natural Gas	1,532,503	2,807,334	$26,360,584	$3,481,313	$4,615,497	$54,664	$34,402,730
DSR	1,968,035	2,949,738	$10,850,901	$1,876,556	$1,569,536	$54,034	$14,242,960
Steam - Coal	2,421,291	2,562,041	$9,191,714	$445,378	$1,987,935	$45,200	$11,579,827
Hydro - Pumped Storage	992,652	1,267,409	$1,765,392	$3,103,366	$187,810	$39,168	$5,017,399
CT - Oil	397,444	571,655	$6,915,751	($2,771,490)	$791,169	$3,723	$4,931,708
Steam - Natural Gas	457,079	502,689	$2,619,111	$597,199	$573,467	$37,435	$3,752,342
Hydro - Run of River	835,951	504,522	$3,574,567	($360,419)	$1,447	$8,655	$3,206,940
RICE - Other	228,852	134,276	$1,302,526	($556,380)	$78,001	$13,603	$810,544
RICE - Natural Gas	54,384	25,039	$839,698	($382,801)	$63,012	$0	$519,910
Steam - Other	62,527	9,151	$483,744	($261,863)	$142,981	$1,219	$363,643
Other	34,112	37,468	$262,343	($29,176)	$58,708	$0	$291,876

The October 1, 2022, changes, removed the prior cap that limited DSR to 33 percent of the cleared synchronized reserves. In the first nine months of 2025, real-time DSR was more than 33 percent of the cleared real-time synchronized reserves in 578 five-minute intervals, 0.7 percent of the total 78,612 five-minute intervals. In the first nine months of 2025, day-ahead DSR was more than 33 percent of the cleared day-ahead synchronized reserves in zero hours. During these 578 five-minute intervals, on average, DSR made up 38.7 percent of the synchronized reserve MW. Figure 10-16 shows the portion of synchronized reserve provided by DSR. Since September 2023, there has been an increase in the use of DSR, but not enough to frequently exceed the former limit.

Figure 10-16 Daily average synchronized reserve from DSR and non-DSR: January 2024 through September 2025



Synchronized Reserve Performance

Resources providing synchronized reserves are paid for being available to respond to a synchronized reserve event and not for the actual response. Synchronized reserve resources are paid for their output in the energy market when they respond to an event.

Actual synchronized reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after the start of the event, and initial output is the lowest output between one minute before the event and one minute after the event.[79]

Cleared synchronized reserve resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. The owner of a cleared resource is penalized if it fails to perform during any synchronized reserve event lasting 10 minutes or longer, although the resource owner can use overperformance from another resource to offset those losses. As synchronized reserve resources are allowed 10 minutes to ramp up to their cleared output, performance penalties are not assessed for events lasting less than 10 minutes.

Table 10-20 shows synchronized reserve event response compliance for events that lasted 10 minutes or longer, using only the response from cleared synchronized reserves. In 2024, five events were 10 minutes or longer. Of those five reserve events, only one was associated with a DCS event. In the first nine months of 2025, four events lasted for at least 10 minutes. One event was due to the loss of a unit and corresponded with a DCS event. In the first nine months of 2025, PJM triggered three events explicitly due to low ACE. For all other DCS events, any associated reserve event lasted less than 10 minutes. PJM has the option, but not the obligation, to trigger a reserve event in response to a DCS event. In some circumstances, PJM system operators will opt to recover the system via regulation and the normal dispatching process.

Actual synchronized reserve response is the total increase in MW from all resources from the moment the spinning event is called to 10 minutes after. The overall response to spinning events was adequate or more than adequate to meet NERC requirements, in which the Reporting ACE must return to the lesser of zero and the value of the Reporting ACE before the disturbance that caused the event.[80] PJM, in practice, not only corrects the Reporting ACE disturbance that led to the event but over corrects. In the four spinning event lasting 10 or more minutes in the first nine months of 2025, the Reporting ACE recovered not just to the NERC required level of zero but overshot by over approximately 1,000 MW.

79 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 134 (Apr. 23, 2025).

80 See PJM. "PJM Manual 12: Balancing Operations," Rev. 55 (Jun. 18, 2025) Attachment D.

Table 10-20 Response compliance for synchronized reserve events 10 minutes or longer by primary fuel and resource type, excluding over response: January 2024 through September 2025[81]

Spin Event	Duration (Minutes)	Primary Resource/Fuel Type	Total Synchronized Reserve Deployed (MW)	Total Capped Synchronized Reserve Resource Response (MW)	Total Synchronized Reserve Resource Shortfall (MW)	Synchronized Reserve Response Percent	Total Synchronized Reserve Response, including Over-Response (MW)	Synchronized Reserve Response Percent, including Over-Response
24-Feb-2024 1548 (EPT)	12.3	Combined Cycle	925	579	347	63%	818	88%
		CT - Natural Gas	445	34	411	8%	49	11%
		DSR	262	20	243	7%	33	13%
		Steam - Coal, Natural Gas	774	28	747	4%	267	34%
		Other	544	67	477	12%	70	13%
		Total	2,951	727	2,225	25%	1,236	42%
08-Jul-2024 1757 (EPT)	14.5	Combined Cycle	700	237	463	34%	277	40%
		CT - Natural Gas, Oil	1,535	696	838	45%	720	47%
		Hydro	261	212	49	81%	220	84%
		Steam - Coal	465	202	263	43%	223	48%
		Steam - Natural Gas, Oil, Other	133	29	104	22%	30	22%
		Other	140	101	39	72%	151	108%
		Total	3,234	1,479	1,755	46%	1,621	50%
21-Jul-2024 1753 (EPT)	10.2	Combined Cycle	560	356	203	64%	487	87%
		CT - Natural Gas	494	327	167	66%	342	69%
		DSR	553	533	20	96%	610	110%
		Hydro	168	130	38	77%	135	80%
		Steam - Coal	530	415	116	78%	498	94%
		Other	74	5	69	7%	7	9%
		Total	2,379	1,589	790	67%	2,079	87%
18-Aug-2024 1604 (EPT)	15.9	Combined Cycle	318	230	88	72%	325	102%
		DSR	529	477	51	90%	599	113%
		Hydro	366	156	210	43%	186	51%
		Steam - Coal	525	417	107	80%	496	94%
		Other	207	61	146	30%	66	32%
		Total	1,945	1,342	603	69%	1,672	86%
10-Nov-2024 0020 (EPT)	10.8	Combined Cycle	555	322	233	58%	397	72%
		DSR	481	451	30	94%	777	162%
		Hydro	305	287	18	94%	556	183%
		Steam - Coal	553	421	132	76%	597	108%
		Other	26	3	24	10%	3	10%
		Total	1,919	1,483	436	77%	2,330	121%
05-Feb-2025 1005 (EPT)	10.0	Combined Cycle	548	411	137	75%	627	115%
		CT - Natural Gas	559	513	46	92%	563	101%
		Steam - Coal	199	106	93	53%	119	60%
		Steam - Natural Gas	120	42	78	35%	46	38%
		Other	412	180	232	44%	267	65%
		Total	1,837	1,252	585	68%	1,623	88%
01-Jul-2025 1018 (EPT)	10.6	Combined Cycle	780	661	119	85%	991	127%
		CT - Natural Gas	963	760	203	79%	848	88%
		DSR	544	406	138	75%	525	96%
		Steam - Coal	345	282	63	82%	332	96%
		Other	287	229	57	80%	237	83%
		Total	2,918	2,337	580	80%	2,933	101%
22-Jul-2025 1511 (EPT)	10.5	Combined Cycle	1,071	909	162	85%	1,197	112%
		CT - Natural Gas	585	510	75	87%	652	112%
		DSR	548	439	110	80%	600	109%
		Steam - Coal	806	611	195	76%	708	88%
		Other	236	141	95	60%	147	62%
		Total	3,246	2,610	636	80%	3,304	102%
25-Sep-2025 1912 (EPT)	10.7	Combined Cycle	813	608	205	75%	775	95%
		CT - Natural Gas	971	829	142	85%	949	98%
		DSR	589	491	98	83%	625	106%
		Hydro - Pumped Storage	376	262	114	70%	563	150%
		Steam - Coal	168	126	42	75%	127	75%
		Steam - Natural Gas, Other	95	52	44	54%	52	55%
		Other	220	198	22	90%	206	94%
		Total	3,232	2,566	666	79%	3,297	102%

81 Results for identified technologies shown only if they are consistent with PJM confidentiality rules.

In the first nine months of 2025, compliance with calls to respond to the single synchronized reserve event was significantly less than 100 percent. Table 10-21 shows the average amount of cleared synchronized reserve MW that responded to events 10 minutes or longer from January 2019 through September 2025. PJM experienced four events longer than 10 minutes in the first nine months of 2025.

Table 10-21 Average synchronized reserve response from scheduled resources for events longer than 10 minutes, excluding over response: January 2019 through September 2025

Year	No. of Events Longer than 10 Minutes	Average Percent of Scheduled Synchronized Reserve MW that Responded
2017	6	87.6%
2018	8	74.2%
2019	3	86.8%
2020	5	59.5%
2021	5	83.1%
2022 (Jan - Sep)	3	71.2%
2022 (Oct - Dec)	7	50.3%
2023	3	55.6%
2024	5	58.2%
2025 (Jan - Sep)	4	78.0%

In Table 10-21, from January 2017 through September 2022, cleared synchronized reserve was provided by tier 2 synchronized reserves, which were cleared when the estimated response from tier 1 resources was insufficient to cover the requirement. Since October 1, 2022, the requirement is fully met by cleared resources that offer the new synchronized reserve product. In the new reserve market, most resources capable of providing reserves were required to offer their full capability as calculated by PJM, whereas previously resources had set their own offer MW. Additionally, while units still set their prices in the new market, the maximum allowed offer price was reduced. Under these new market rules, there was a much larger pool of resources offering synchronized reserves, but the resources clearing the reserve market changed. In the months immediately following the change, PJM was clearing less DSR and fewer natural gas CTs and more combined cycles and steam coal units, a portion of which had not cleared in the months leading up to the change. This, in part, lead to the drop in synchronized reserve performance seen in Table 10-21.

In 2024, when PJM and the MMU inquired about poorly performing resources, responses pointed towards shortcomings in how resources were deployed. Although resources are required to fully respond within 10 minutes, resources do not necessarily have a full 10 minutes to respond. PJM schedules reserve MW with the expectation that resources will start responding as soon as an event begins, but this expectation fails to consider communication delays that result from how a resource's market operation center (MOC) notifies the resource of events. When a MOC receives PJM's ALL-CALL, it can take several minutes for the MOC to acknowledge the call and to contact the appropriate resources, which then can take minutes more to start responding.

The MMU recommends that, to minimize lag, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and to have the ability to automatically respond to the notifications. PJM currently has an optional inter-control room connection protocol (ICCP) signal that some control rooms use, but PJM does not track who is actually using it. This or another form of electronic signal should be required for all resources. Stakeholders approved a joint PJM/MMU proposal to implement an electronic communications and reserve deployment process on July 24, 2024. On December 17, 2024, PJM implemented changes to augment the SCED dispatch signal to include reserve response during reserve events. However, this new process is not required for all synchronized reserve resources and does not replace the ALL-CALL. The new process mainly benefits units that automatically respond to the dispatch signal, such as by following AGC. Between December 17, 2024, and the end of September 2025, there were only four events lasting 10 or more minutes with which to sufficiently test the augmented dispatch signal. For the event on February 5, 2025, PJM took explicit action to make the event last long enough for testing.

The penalty structure when a resource fails to respond fully to a spinning event has two components. The first component is, for each interval during the day on which the event occurred, the forfeiture of awarded SRMCP credits in the amount of the lesser of the resource's capped synchronized reserve assignment during that interval and the resource's maximum shortfall MW during that day. The second component is a required return of SRMCP credits paid in the Immediate Past Interval (IPI), equal to the sum of, for each scheduled interval within the IPI, the SRMCP multiplied by the lesser of a resource's capped MW assignment during the penalized interval and the resource's penalty obligation for the day of the event. The IPI is defined as the average time, in number of days, since the start of the previous event over the previous two years or, if less, the number of days since the resource last failed to fully respond. For example, the maximum IPI for 2025 is 20 days and was calculated using the events from November 1, 2022 through October 31, 2024.[82]

There are several problems with this penalty structure.[83] First, resource owners are permitted to aggregate the response of multiple cleared reserve resources within the same portfolio, allowing owners to reduce the penalty obligation of a resource's underresponse by offsetting it with another scheduled resource's overresponse.[84] Second, the maximum IPI is calculated using events of any length, even though a resource is automatically considered compliant for events less than 10 minutes in length, artificially and significantly shortening the applied IPI. Third, the historical component of the penalty only applies to a resource's SRMCP credits, but not to LOC credits, even though a large portion of credits is awarded for LOC. For the four events that lasted for 10 or more minutes in the first nine months of 2025, for each resource interval in which the resource's penalty obligation MW was greater than or equal to the resource's capped MW during the penalized interval, the total historical penalty was $233,142 and the total LOC credit was $44,598.

The penalty structure for synchronized reserve nonperformance does not provide appropriate or reasonable performance incentives. Under the current penalty structure and due to the low frequency of sufficiently long events, it is possible for a resource to not respond to any spin events and yet still receive net revenues for providing synchronized reserve. The MMU continues to recommend that the penalty's repayment include the LOC credits in addition to the SRMCP credits. The MMU also recommends that a unit that fails to respond to a synchronized reserve event 10 minutes or longer repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer. A resource should not be paid for reserves that it does not provide.

The MMU also continues to recommend that aggregation not be permitted to offset resource specific penalties for failure to respond to a synchronized reserve event. Including aggregate responses from all cleared resources weakens the incentive to perform and creates an incentive to withhold reserves from other resources. Synchronized reserve commitment is resource specific, so the obligation to respond should also be resource specific.

Table 10-22 shows the possible total historical penalty if the historical penalty had been defined differently in a single aspect for the first nine months of 2025 for the one event that was 10 or more minutes in length. It compares the status quo, the amount if the IPI were defined using only events of 10 or more minutes, the amount if LOC credits were penalized in an amount proportionate to the shortfall, and if aggregate response were not allowed. As can be seen in the table, the values are similar for the status quo, for penalizing LOC credits, and for disallowing aggregate response. The larger effect of only using 10-minute events to calculate the IPI is due to using a 50-day IPI compared to PJM's current 20-day IPI. The 150 percent increase to the IPI is a consequence of PJM's increase to the synchronized reserve reliability requirement. As shown by Table 10-21, that change decreased the number of events of 10 or more minutes, increasing the time between such events.

82 See "2024 Third Quarter Synchronized Reserve Performance," PJM presentation to the Operations Committee. (December 5, 2024) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2024/20241205/20241205-item-12---synchronous-reserve-update.pdf>.
83 See "IMM Proposal: Reserve Deployment and Compensation," IMM presentation to the Reserve Certainty Senior Task Force. (March 13, 2024) <https://pjm.com/-/media/committees-groups/task-forces/rcstf/2024/20240313/20240313-item-02---imm-proposal---deployment-and-compensation.ashx>
84 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.3 Charges for Synchronized Reserve, Rev. 100 (Jun. 1, 2025).

Table 10-22 Comparison of historical/retroactive penalties using possible different definitions: January through September, 2025

Description	Total Retroactive Penalty
Status Quo	$2,345,747
Using only 10-minute events for IPI	$5,496,255
Including LOC credits in retroactive penalty	$2,586,050
Disallowing aggregate response	$2,589,936
All three changes	$7,030,601

Resources should not be paid for reserves that they do not provide. The MMU recommends reclaiming credits back to the last known fully compliant performance, while providing the opportunity to demonstrate performance between events. Resources do not control when PJM calls 10-minute events, nor do they control whether they are scheduled during the few 10-minute events that PJM calls. While actual performance is the key to not being penalized, those factors contribute to defining penalties for many resources. The solution is not to arbitrarily limit the penalized period, as PJM does with its IPI, but to instead provide opportunities, between events, for resources to demonstrate that they are capable of providing reserves.

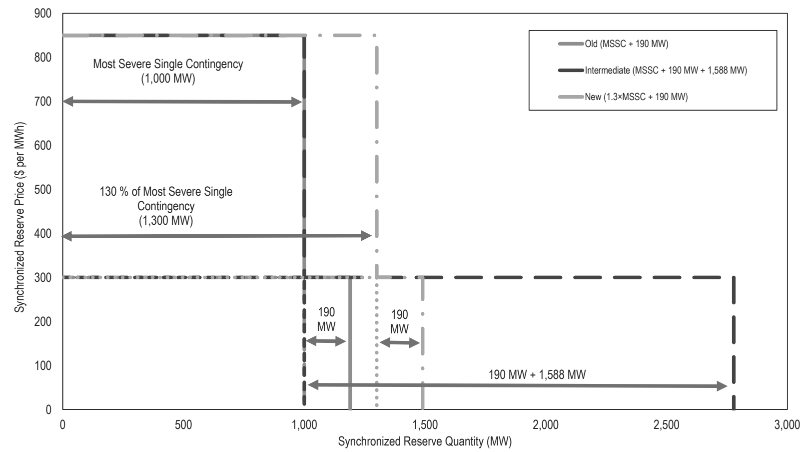
PJM's 2023 Response to Poor Unit Specific Performance

On October 1, 2022, PJM implemented substantial changes to the reserves markets, called Reserve Pricing Formation, meant to improve reserve reliability and improve accuracy when calculating reserve supply. Winter Storm Elliot occurred in December 2022. In the nine synchronized reserve events from October 2022 through April 2022, the average reserve performance was 53.7 percent. Excluding the events of Winter Storm Elliot, it was 49.4 percent.

In May 2023, in response to poor unit specific reserve performance since the market changes made on October 1, 2022, PJM made two unilateral decisions without approval from stakeholders or FERC. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the MSSC.

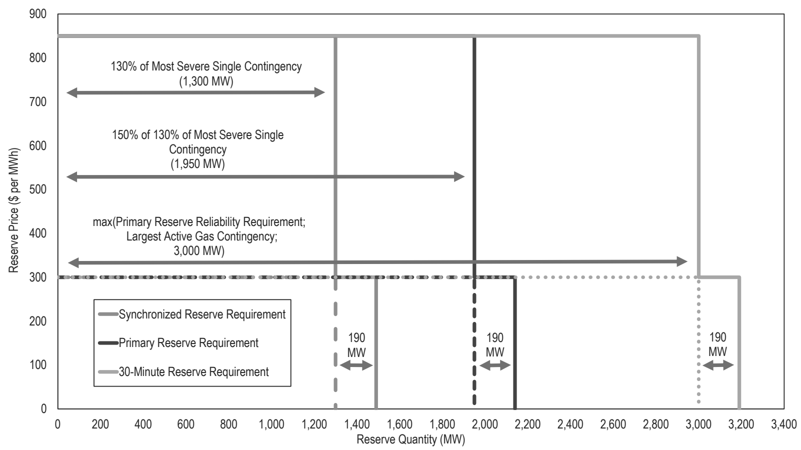
Figure 10-17 compares, for an example MSSC of 1,000 MW, the initial synchronized reserve ORDC from before these changes, the intermediate ORDC with the extension to the second step, and the new ORDC with the increase in the first step.

Figure 10-17 An example comparison of the old, intermediate, and new real-time synchronized reserve ORDCs



Because the definitions of the reserve reliability requirements are nested, PJM's increase to the synchronized reserve reliability requirement also increased the primary reserve reliability requirement, which in turn increased the 30-minute reserve reliability requirement. Figure 10-18 shows the new ORDCs of the three reserve services using an example MSSC of 1,000 MW and the default 190 MW for the extended requirements. Figure 10-5 shows the original ORDCs for the same example MSSC. As seen in Figure 10-2, although not shown in Figure 10-18, as a result of the increase, the 30-minute reserve requirement is now usually equal to the primary reserve requirement.

Figure 10-18 An example of the reserve services' new real-time operating reserve demand curves, including the permanent second steps



PJM did not have the authority to increase the extended reserve requirements without a hot or cold weather alert or an emergency condition. The most common cause of doubled synchronized reserve requirement in the first four months of 2023 and in prior years was the possibility of large units tripping or being disconnected while undergoing maintenance work, which is a clear increase in the size of the most severe single contingency.

The doubling of the requirement for May 12 to May 16, 2023, lead to 31 intervals of shortage pricing for synchronized reserve and primary reserve in the RTO, even though, based on the actual contingencies, both services cleared well in excess of what was actually needed. In addition, because there was no spin event on either May 12 or May 15, it is unknown whether the response that could have been gained by this increase in demand justified these higher prices.

After making these changes, PJM later modified Manual 11 to allow "temporarily" increasing contingency reserve requirements "as necessary to account for resource performance."[85] Neither temporary nor resource performance criteria are specified or defined in the manual. PJM announced criteria for reducing the increase to the synchronized reserve reliability requirement in the PJM Operating Committee on March 6, 2025.[86]

PJM already clears additional 10-minute reserve in the form of nonsynchronized reserve. PJM had and continues to have the option to use all 10-minute reserve that it clears for recovering within 10 minutes, but instead chooses to increase the amount of all 10-minute reserve that PJM clears, even though it only uses a subset.[87] Despite PJM's unexplained reluctance to call a nonsynchronized reserve event, PJM does use NSR resources to respond to synchronized reserve events. That PJM occasionally uses certain nonsynchronized resources to respond to synchronized reserve events while wishing to avoid the general use of NSR suggests a mismatch between NSR's definition, its actual characteristics, and PJM's definition of its operational needs.

PJM gave several reasons to support the changes to the reserve ORDCs, including that resource response to spin events has been poor and that the average length of spin events greater than 10 minutes has increased. In addition, PJM was concerned that it might be less able to avoid Disturbance Control Standard (DCS) violations, in which PJM would exceed the NERC-imposed 15-minute limit for recovering Reporting ACE from changes due to Reportable Disturbances.[88] The MMU agrees about the underlying facts, with caveats, but does not agree with PJM's assertions about the reasons for poor performance, or with the assumption about DCS events or that any of these reasons support PJM's actions.

The MMU agrees that the average length of reserve events has increased, but notes that recent DCS event lengths have remained well below requirements, except in one case. On December 26, 2022, during Winter Storm Elliott, PJM recovered from a DCS event in 15 minutes and 52 seconds, longer than NERC's

85 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 6.3 Charges for Synchronized Reserve, Rev. 134 (Apr. 23, 2025). "In order to meet Reliability First (RF) Regional Criteria, PJM may schedule additional Contingency Reserves on a temporary basis in order to meet the Largest Single Contingency, as necessary to account for resource performance. PJM shall post details regarding additional scheduling of reserves in Markets Gateway."
86 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.
87 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 55 (Jun. 18, 2025).
88 See PJM. "PJM Manual 12: Balancing Operations," Rev. 55 (Jun. 18, 2025) Attachment D.

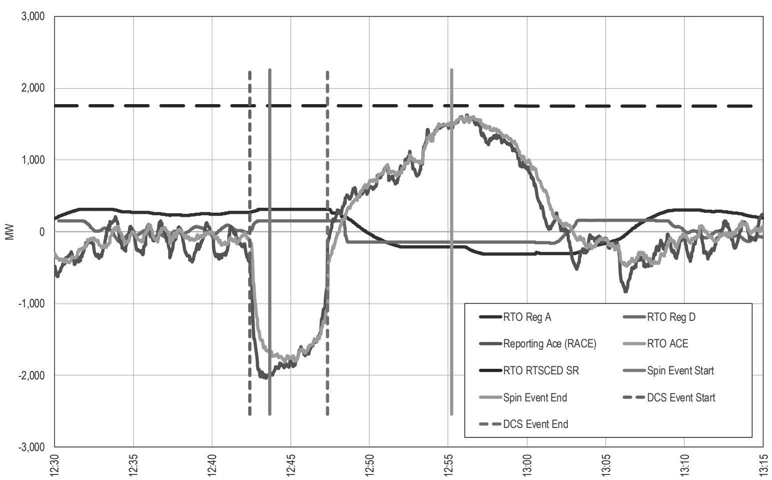
requirement of recovery within 15 minutes. Due to possible extenuating circumstances, NERC has yet to determine whether that recovery was actually a DCS violation. Regardless, the data do not support the assertion that PJM is at risk of violating NERC standards during nonemergency conditions and the data do not support the assertion that there has been a change in PJM's DCS event response times. In general, PJM's recovery times are clearly and significantly shorter than NERC's 15-minute requirement and PJM's self-imposed 10-minute requirement. In many cases, PJM recovers Reporting ACE within five minutes. Table 10-23 compares the lengths of recent DCS events with the lengths of their corresponding spin events. As can be seen, many spin events are minutes longer than the DCS event for which they were triggered. In the cases where a spin event continues for more than 10 minutes, this can mean that resource performance becomes subject to evaluation for spin events whose purpose had already been achieved minutes ago (that is, the recovery of the Reporting ACE and the end of the DCS event). While there are reasons for PJM dispatchers to continue a spin event even after ACE recovers, Table 10-23 shows that the lengths of spin events do not suggest that PJM has become closer to having a DCS violation. Table 10-23 also shows that the lengths of DCS events with corresponding spin events from before the changes to the reserve markets were implemented on October 1, 2022, are not significantly different from the lengths of such events since then.

Table 10-23 A comparison of the lengths of recent DCS events with that of their corresponding spin events: January 2022 through September 2025

DCS Start	DCS End	DCS Length	Spin Start	Spin End	Spin Length
03-Mar-2022 1218 (EPT)	03-Mar-2022 1224 (EPT)	00:06:03	03-Mar-2022 1220 (EPT)	03-Mar-2022 1227 (EPT)	00:07:21
06-Apr-2022 1144 (EPT)	06-Apr-2022 1149 (EPT)	00:05:12	06-Apr-2022 1145 (EPT)	06-Apr-2022 1155 (EPT)	00:09:43
14-Apr-2022 0928 (EPT)	14-Apr-2022 0934 (EPT)	00:05:40	14-Apr-2022 0930 (EPT)	14-Apr-2022 0938 (EPT)	00:08:07
16-May-2022 1531 (EPT)	16-May-2022 1537 (EPT)	00:06:12	16-May-2022 1532 (EPT)	16-May-2022 1543 (EPT)	00:11:05
16-May-2022 1553 (EPT)	16-May-2022 1556 (EPT)	00:03:18	16-May-2022 1553 (EPT)	16-May-2022 1603 (EPT)	00:09:34
23-May-2022 1717 (EPT)	23-May-2022 1720 (EPT)	00:03:17	23-May-2022 1717 (EPT)	23-May-2022 1732 (EPT)	00:15:00
27-Jun-2022 1700 (EPT)	27-Jun-2022 1704 (EPT)	00:04:16	27-Jun-2022 1701 (EPT)	27-Jun-2022 1710 (EPT)	00:09:03
07-Jul-2022 1720 (EPT)	07-Jul-2022 1724 (EPT)	00:03:27	07-Jul-2022 1721 (EPT)	07-Jul-2022 1729 (EPT)	00:07:52
26-Sep-2022 0335 (EPT)	26-Sep-2022 0342 (EPT)	00:06:16	26-Sep-2022 0339 (EPT)	26-Sep-2022 0345 (EPT)	00:06:02
29-Oct-2022 0210 (EPT)	29-Oct-2022 0215 (EPT)	00:04:42	29-Oct-2022 0212 (EPT)	29-Oct-2022 0224 (EPT)	00:11:52
04-Nov-2022 1501 (EPT)	04-Nov-2022 1504 (EPT)	00:02:58	04-Nov-2022 1503 (EPT)	04-Nov-2022 1507 (EPT)	00:04:25
29-Nov-2022 1629 (EPT)	29-Nov-2022 1638 (EPT)	00:08:23	29-Nov-2022 1630 (EPT)	29-Nov-2022 1647 (EPT)	00:16:45
24-Dec-2022 0223 (EPT)	24-Dec-2022 0228 (EPT)	00:05:15	24-Dec-2022 0223 (EPT)	24-Dec-2022 0254 (EPT)	00:30:35
05-Jan-2023 1242 (EPT)	05-Jan-2023 1247 (EPT)	00:04:56	05-Jan-2023 1243 (EPT)	05-Jan-2023 1255 (EPT)	00:11:33
10-Aug-2023 0039 (EPT)	10-Aug-2023 0043 (EPT)	00:04:02	10-Aug-2023 0041 (EPT)	10-Aug-2023 0049 (EPT)	00:07:33
14-Dec-2023 1939 (EPT)	14-Dec-2023 1943 (EPT)	00:03:58	15-Dec-2023 0041 (EPT)	15-Dec-2023 0053 (EPT)	00:12:15
19-Dec-2023 0449 (EPT)	19-Dec-2023 0450 (EPT)	00:01:25	19-Dec-2023 1451 (EPT)	19-Dec-2023 1458 (EPT)	00:06:30
13-Jan-2024 0157 (EPT)	13-Jan-2024 0201 (EPT)	00:04:26	13-Jan-2024 0159 (EPT)	13-Jan-2024 0204 (EPT)	00:05:15
25-Jan-2024 1237 (EPT)	25-Jan-2024 1241 (EPT)	00:04:48	25-Jan-2024 1239 (EPT)	25-Jan-2024 1247 (EPT)	00:08:37
29-Jan-2024 1202 (EPT)	29-Jan-2024 1206 (EPT)	00:04:35	29-Jan-2024 1203 (EPT)	29-Jan-2024 1212 (EPT)	00:08:54
24-Feb-2024 1546 (EPT)	24-Feb-2024 1551 (EPT)	00:05:36	24-Feb-2024 1548 (EPT)	24-Feb-2024 1600 (EPT)	00:12:19
04-Apr-2024 1047 (EPT)	04-Apr-2024 1052 (EPT)	00:04:45	04-Apr-2024 1050 (EPT)	04-Apr-2024 1055 (EPT)	00:05:15
03-Jun-2024 1852 (EPT)	03-Jun-2024 1858 (EPT)	00:06:41	03-Jun-2024 1853 (EPT)	03-Jun-2024 1902 (EPT)	00:08:35
29-Jun-2024 2101 (EPT)	29-Jun-2024 2106 (EPT)	00:04:48	29-Jun-2024 2103 (EPT)	29-Jun-2024 2109 (EPT)	00:05:36
12-Aug-2024 1709 (EPT)	12-Aug-2024 1713 (EPT)	00:04:25	12-Aug-2024 1710 (EPT)	12-Aug-2024 1720 (EPT)	00:09:39
26-Aug-2024 1352 (EPT)	26-Aug-2024 1355 (EPT)	00:02:48	26-Aug-2024 1353 (EPT)	26-Aug-2024 1357 (EPT)	00:04:13
27-Nov-2024 1934 (EPT)	27-Nov-2024 1939 (EPT)	00:04:35	27-Nov-2024 1934 (EPT)	27-Nov-2024 1946 (EPT)	00:11:57
11-Dec-2024 0819 (EPT)	11-Dec-2024 0823 (EPT)	00:04:00	11-Dec-2024 0821 (EPT)	11-Dec-2024 0827 (EPT)	00:06:00
05-Feb-2025 1003 (EPT)	05-Feb-2025 1007 (EPT)	00:03:49	05-Feb-2025 1005 (EPT)	05-Feb-2025 1015 (EPT)	00:10:02
06-Feb-2025 1355 (EPT)	06-Feb-2025 1358 (EPT)	00:02:39	06-Feb-2025 1356 (EPT)	06-Feb-2025 1401 (EPT)	00:04:59
05-Apr-2025 0420 (EPT)	05-Apr-2025 0424 (EPT)	00:03:54	05-Apr-2025 0421 (EPT)	05-Apr-2025 0429 (EPT)	00:08:22
24-Apr-2025 0048 (EPT)	24-Apr-2025 0052 (EPT)	00:04:49	24-Apr-2025 0050 (EPT)	24-Apr-2025 0057 (EPT)	00:06:43
19-May-2025 1145 (EPT)	19-May-2025 1149 (EPT)	00:04:14	19-May-2025 1146 (EPT)	19-May-2025 1153 (EPT)	00:07:31
01-Jul-2025 1016 (EPT)	01-Jul-2025 1021 (EPT)	00:04:49	01-Jul-2025 1018 (EPT)	01-Jul-2025 1029 (EPT)	00:10:39
22-Jul-2025 1510 (EPT)	22-Jul-2025 1513 (EPT)	00:03:08	22-Jul-2025 1511 (EPT)	22-Jul-2025 1522 (EPT)	00:10:32
30-Jul-2025 1330 (EPT)	30-Jul-2025 1333 (EPT)	00:02:41	30-Jul-2025 1331 (EPT)	30-Jul-2025 1337 (EPT)	00:05:58
31-Jul-2025 0132 (EPT)	31-Jul-2025 0136 (EPT)	00:03:56	31-Jul-2025 0133 (EPT)	31-Jul-2025 0139 (EPT)	00:06:17
15-Aug-2025 1531 (EPT)	15-Aug-2025 1534 (EPT)	00:02:37	15-Aug-2025 1533 (EPT)	15-Aug-2025 1538 (EPT)	00:05:23
29-Sep-2025 2128 (EPT)	29-Sep-2025 2132 (EPT)	00:03:58	29-Sep-2025 2130 (EPT)	29-Sep-2025 2136 (EPT)	00:06:45

As an example of the differences between the lengths of spin events and the lengths of DCS events, Figure 10-19 shows PJM ACE during a DCS event and its corresponding spin event on January 5, 2023. The DCS event lasted 4 minutes and 56 seconds, while the spin event lasted 11 minutes and 33 seconds, more than twice as long. The DCS event ended when Reporting ACE (RACE) recovered to its level at the time of the loss of supply, while the spin event ended based on PJM discretion.

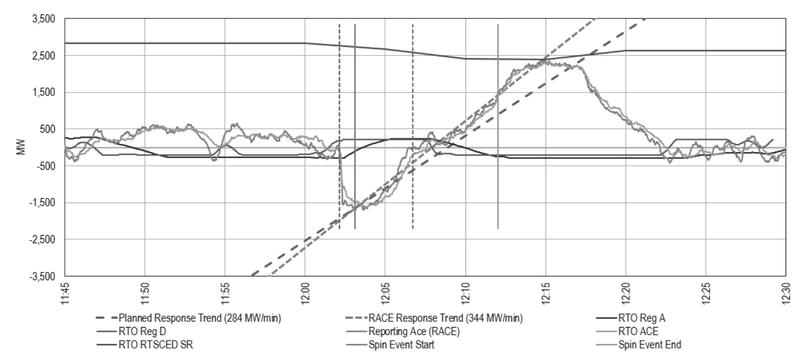
Figure 10-19 DCS Event vs. Spin Event: January 5, 2023



If the basis of the original definition of the synchronized reserve reliability requirement was an amount of MW needed to recover within 10 minutes, then an increase in the amount of cleared reserves can shorten the length of synchronized reserve events to be less than 10 minutes. In the remainder of 2023 after the increase in the reliability requirement in May 2023, there were eight spin events, of which seven were less than 10 minutes. Similarly, of the 19 spin events in 2024, 13 were less than 10 minutes. Of the 19 events in the first nine months of 2025, PJM triggered only four events of 10 or more minutes. That one event was allowed to reach the 10-minute mark so that PJM could fully test the new deployment method implemented in December 2024. If not for that, it also would have been less than 10 minutes. Because these shorter events lasted less than 10 minutes, only a small portion of the events since the increase qualify for performance assessment under the PJM Market Rules. PJM has stated that they monitor performance for events less than 10 minutes. If the PJM analysis fails to consider the lags that the ALL-CALL system introduces, different for each contacted resource, then it will continue to show underperformance.

In 35 of the 45 spin events for the RTO Reserve Zone that have occurred since the reserve requirement increase in May 2023 through the first nine months of 2025, ACE response is consistent with the rate of recovery that would be expected if reserves had performed adequately. Figure 10-20 shows one such event on January 29, 2024. However, some resources are responding to PJM's event notifications when they did not clear the reserve market, so they do not have reserve assignments during those events and so do not count towards reserve performance. PJM has defined the problem as one not of poor overall system response nor of poor ACE recovery, but one of poor performance from the assigned reserves. At the Operating Committee on March 6, 2025, PJM announced that they would decrease the adder to the synchronized reserve reliability requirement if average event performance were greater than 75 percent for qualifying events. Under these announced criteria, qualifying events would be any 10-minute event and any shorter event in which event performance was at least 75 percent. Even with these criteria, the fact that performance remains unsatisfactory for multiple events in the months with the increased requirements is evidence that the increase is not the correct solution to the asserted problem.

Figure 10-20 ACE response during a synchronized reserve event: January 29, 2024 from 12:03 to 12:12 EPT



The MMU disagrees with PJM that increasing the reserve requirement is the correct solution for accounting for poor reserve performance.[89] The MMU's position is that these problems with the supply of reserves should not be solved by changing the demand for reserves. The situation is a problem on the supply side, and it should be dealt with and solved on the supply side. The repeated lack of response means that resource personnel are insufficiently trained or that resource data inputs, such as ramp rates, the times needed for condensers to start, and economic maximums, are incorrect. It is the responsibility of market participants to correct their offer parameters and operating parameters. It is their obligation to submit correct data.

The data on synchronized reserve event recovery do not support the conclusion that there is an immediate need to change how reserves clear. If PJM insists on an immediate change, the focus should be on correcting the supply of reserves rather than increasing demand.

PJM's logic is that because reserves are responding at an average rate of about 50 percent during spin events, the solution is to buy twice as many MW of reserves. The result is that PJM is overpaying for reserve MW. PJM is paying for 1.0 MW but receiving 0.5 MW. PJM's solution is to pay for 2.0 MW in order to receive 1.0 MW.

Instead of increasing the demand requirement, the MMU proposes to purchase reserve MW from resources only in the amounts for which they can actually perform. If an underperforming resource's behavior shows that they can only reliably provide five MW of reserve, then PJM should only be purchasing five MW of reserve from them. PJM should not be paying MCP credit for MW that are not reliably provided, especially when it only recovers a portion of that money later via penalties and charges.

The MMU proposal is to pay for 0.5 MW from the underperforming unit. The MMU proposal is to pay for actual unit specific MW. The MMU proposal is to pay for 0.5 MW from each of two underperforming units. The result is to pay for 1.0 MW and to receive 1.0 MW of reserves. The MMU proposal is to buy the correct amount of reserves. No increase in demand is required.

89 See "Market Monitor Report," MMU presentation to the Members Committee Webinar. (May 22, 2023) <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230522-webinar/item-04---imm-report.ashx>.

The solution is not to buy more MW of poorly performing reserves. The solution is to accurately recognize the actual supply of reserves. The solution is to buy the correct amount of reserves, accounting for the actual performance of supply.

A focus on the supply side issues should be implemented immediately: ensure correct and timely signals; provide education on requirements; buy required reliable MW, based on actual performance; pay only for reliable MW based on actual performance; and do not pay for MW not provided. Detailed, unit by unit analysis of the reasons for poor performance is needed. Potential unit specific issues include: ensuring the ability to receive and respond to signals; discontinuities in offer curves; the accuracy of ramp rates; ambient derates; fuel availability; demand side resource response; failure to follow dispatch; incorrect eco max or spin max; and incorrect parameters.

One result of PJM's changes to the reserve requirements is that the total cost of the synchronized reserve market has increased. For May 2023 through December 2023, total credits paid for synchronized reserve were $66.7 million in eight months or $8.3 million per month, compared to $6.4 million in four months or $1.6 million per month for January 2023 through April 2023. In 2024, the total credits paid for synchronized reserve were $74.1 million or $6.2 million per month. In the first nine months of 2025, the total credits paid for synchronized reserve were $117.3 million or $13.0 million per month. Table 10-18 shows the total payments and charges for synchronized reserve by month. The cost of underperformance by reserve suppliers is paid by PJM customers, while it should be incurred by the suppliers who fail to meet their responsibilities. If reserve suppliers cannot provide the energy that they offer and clear during synchronized reserve events, they should not be paid from the last time they successfully responded to a spin event. These suppliers are not accurately representing their true capability to the PJM market and/or have failed to establish processes to ensure that they follow PJM's instructions.

On March 6, 2025, PJM presented to the PJM Operating Committee its criteria for decreasing (or increasing) the adder to the synchronized reserve reliability requirement by reviewing the average performance of non-overlapping sets of three qualifying events.[90] [91] A qualifying event is an event lasting at least 10 minutes or an event whose performance was at least 75 percent of the total reserve assignment. This performance is based on a resource's scheduled MW, not the MW amount that PJM uses its tools to deploy. The adder is defined as a percentage of the most severe single contingency. Table 10-24 shows the average performance required for each level of adjustment, with the adder not to exceed 30 percent of the most severe single contingency. Since the increase to the requirement, the number of 10-minute events has decreased. In the first nine months of 2025, there have been only four events lasting 10 or more minutes. For the event on February 5, 2025, PJM acknowledged that operators let the event run long enough to fully test the new deployment mechanism. If it had been handled in the usual manner, that event too would have been less than 10 minutes. Therefore, under PJM's criteria, the effect of the adder means that it will take longer to remove the adder, even though shorter events are, by definition, successful events. That a shorter event does not achieve 75 percent performance in less than, for example, five minutes, is not necessarily indicative of a problem, because the only defining performance requirement for the synchronized reserve product is that it should achieve full performance by the tenth minute. Only events lasting 10 or more minutes can be true measures of under-performance. If PJM receives so great a response that it is difficult to allow an event to last at least 10 minutes, that is another indication that the adder should be removed immediately.

As shown by Table 10-20, poor performance is not an across the board problem, yet PJM's current criteria and approach treat it as if it were. Reserve supply issues are resource specific and should be addressed at the resource level, such as by requiring support for an electronic deployment signal. Increasing the requirement does not change resource behavior. Engaging with poorly performing resources, as the MMU and PJM have been doing, does change behavior. Reserve testing would allow PJM to identify underperforming resources that would benefit from unit specific engagement. Such identification would be proactive instead of reactive, improving event performance.

90 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

91 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (May 8, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250508/20250508-item-20---synchronized-reserve-for-reliability-update.pdf>.

Table 10-24 PJM criteria for adjusting the adder in the synchronized reserve reliability requirement

Average Performance	Adder Adjustment
Below 70%	Increase by 10 percentage points
Above 75%	Decrease by 10 percentage points
Above 85%	Decrease by 20 percentage points
Above 95%	Decrease by 30 percentage points

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[92] [93] A disturbance is defined as loss of the lesser of 900 MW and 80 percent of the largest single contingency within 60 seconds. In the absence of a disturbance, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE. Of the 12 spin events that occurred in 2023, three were explicitly due to low ACE, of which all were shorter than 10 minutes. Of the 19 events that occurred in 2024, two were explicitly due to low ACE, of which one was longer than 10 minutes. In the first nine months of 2025, PJM triggered three events explicitly due to low ACE, with all three events being less than 10 minutes long.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for 30 minutes at the most. When reserve output is still needed after 30 minutes, that output should come from secondary reserves, not synchronized reserves.

From January 2020 through September 2025, PJM experienced 108 synchronized reserve events, approximately 1.6 events per month, with an average duration of 10.8 minutes. Table 10-25 shows these events with their region and their duration rounded to the nearest tenth of a minute.

92 *2012 Annual State of the Market Report for PJM*, Appendix E – PJM's DCS Performance.

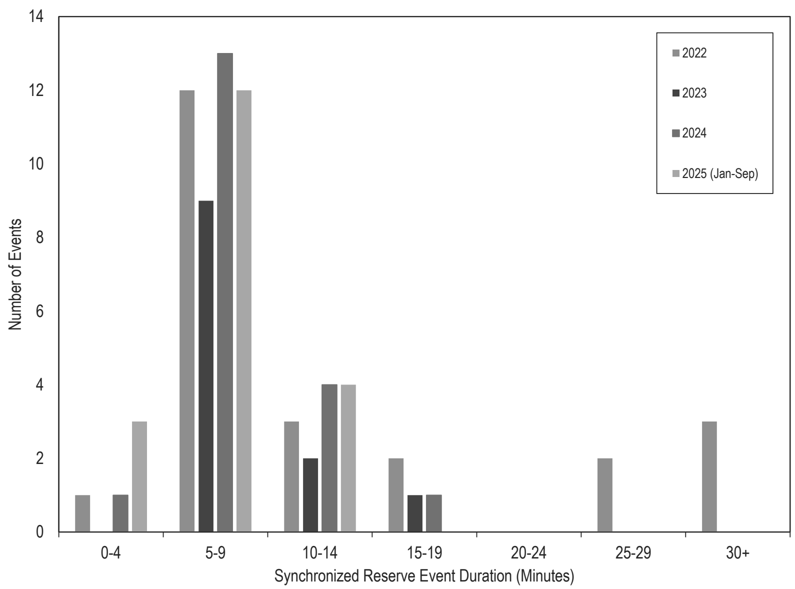
93 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 55 (Jun. 18, 2025).

Table 10-25 Synchronized reserve events: January 2020 through September 2025

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
20-Jan-2020 1406 (EPT)	MAD	7.8	03-Jan-2022 1227 (EPT)	RTO	8.9	13-Jan-2024 0159 (EPT)	RTO	5.3
23-Jan-2020 1617 (EPT)	RTO	8.7	03-Mar-2022 1220 (EPT)	RTO	7.4	25-Jan-2024 1239 (EPT)	RTO	8.6
07-Feb-2020 1206 (EPT)	RTO	6.4	06-Apr-2022 1145 (EPT)	RTO	9.7	29-Jan-2024 1203 (EPT)	RTO	8.9
08-Feb-2020 0344 (EPT)	RTO	8.4	13-Apr-2022 1725 (EPT)	RTO	28.5	24-Feb-2024 1548 (EPT)	MAD	12.3
10-Feb-2020 2015 (EPT)	RTO	9.6	14-Apr-2022 0931 (EPT)	RTO	8.1	04-Apr-2024 1050 (EPT)	RTO	5.3
18-Feb-2020 1116 (EPT)	RTO	10.0	16-May-2022 1532 (EPT)	RTO	11.1	13-Apr-2024 0036 (EPT)	RTO	7.1
08-Mar-2020 0517 (EPT)	MAD	5.6	16-May-2022 1553 (EPT)	RTO	9.6	03-Jun-2024 1853 (EPT)	RTO	8.6
13-Apr-2020 2001 (EPT)	RTO	7.9	23-May-2022 1717 (EPT)	RTO	15.0	29-Jun-2024 2103 (EPT)	RTO	5.6
03-May-2020 1229 (EPT)	RTO	6.6	26-May-2022 1409 (EPT)	RTO	6.3	08-Jul-2024 1757 (EPT)	RTO	14.5
06-Jul-2020 2122 (EPT)	RTO	10.4	22-Jun-2022 1506 (EPT)	RTO	7.2	18-Jul-2024 1524 (EPT)	RTO	7.0
24-Jul-2020 0103 (EPT)	RTO	9.9	27-Jun-2022 1701 (EPT)	RTO	9.1	21-Jul-2024 1753 (EPT)	RTO	10.2
25-Jul-2020 1639 (EPT)	MAD	11.7	07-Jul-2022 1721 (EPT)	RTO	7.9	12-Aug-2024 1710 (EPT)	RTO	9.7
10-Sep-2020 0019 (EPT)	RTO	9.5	26-Sep-2022 0339 (EPT)	RTO	6.0	18-Aug-2024 1604 (EPT)	RTO	15.9
10-Oct-2020 1852 (EPT)	RTO	7.7	29-Sep-2022 1025 (EPT)	RTO	6.2	26-Aug-2024 1353 (EPT)	RTO	4.2
12-Oct-2020 0429 (EPT)	RTO	9.3	29-Oct-2022 1412 (EPT)	RTO	11.9	22-Oct-2024 1002 (EPT)	RTO	6.2
13-Nov-2020 0746 (EPT)	RTO	5.9	04-Nov-2022 1503 (EPT)	RTO	4.4	10-Nov-2024 0020 (EPT)	RTO	10.8
16-Dec-2020 1638 (EPT)	MAD	10.4	14-Nov-2022 22:01 (EPT)	RTO	6.7	27-Nov-2024 1936 (EPT)	RTO	10.0
			29-Nov-2022 1630 (EPT)	RTO	16.8	29-Nov-2024 1103 (EPT)	RTO	7.4
24-Jan-2021 2232 (EPT)	RTO	6.5	23-Dec-2022 1014 (EPT)	RTO	11.1	11-Dec-2024 0821 (EPT)	RTO	6.0
09-Mar-2021 0751 (EPT)	RTO	10.9	23-Dec-2022 1617 (EPT)	RTO	111.5			
13-Apr-2021 2005 (EPT)	RTO	8.9	24-Dec-2022 0501 (EPT)	RTO	25.7	21-Jan-2025 0520 (EPT)	RTO	4.7
30-Apr-2021 2030 (EPT)	RTO	11.6	24-Dec-2022 0223 (EPT)	RTO	30.6	05-Feb-2025 1505 (EPT)	RTO	10.0
26-May-2021 1417 (EPT)	RTO	10.0	24-Dec-2022 0423 (EPT)	RTO	87.5	06-Feb-2025 1856 (EPT)	RTO	5.0
21-Jun-2021 0554 (EPT)	RTO	7.0				11-Feb-2025 1404 (EPT)	RTO	5.3
23-Jun-2021 0333 (EPT)	RTO	4.7	05-Jan-2023 1243 (EPT)	RTO	11.6	05-Apr-2025 0421 (EPT)	RTO	8.4
21-Jul-2021 1828 (EPT)	RTO	5.0	10-Jan-2023 0706 (EPT)	RTO	17.5	24-Apr-2025 0050 (EPT)	MAD	7.1
25-Jul-2021 1617 (EPT)	RTO	6.1	26-Jan-2023 1452 (EPT)	MAD	6.9	19-May-2025 1146 (EPT)	RTO	7.5
23-Aug-2021 1644 (EPT)	RTO	17.6	02-Feb-2023 0606 (EPT)	RTO	8.0	22-Jun-2025 1937 (EPT)	RTO	7.8
24-Aug-2021 1038 (EPT)	RTO	8.2	28-May-2023 2009 (EPT)	RTO	7.4	01-Jul-2025 1018 (EPT)	RTO	10.6
27-Sep-2021 1656 (EPT)	RTO	8.4	11-Jun-2023 1611 (EPT)	MAD	8.7	22-Jul-2025 1511 (EPT)	RTO	11.5
11-Oct-2021 0923 (EPT)	RTO	9.3	23-Jun-2023 1905 (EPT)	RTO	7.0	30-Jul-2025 1331 (EPT)	RTO	6.0
16-Oct-2021 0130 (EPT)	RTO	7.7	08-Aug-2023 0041 (EPT)	RTO	7.6	31-Jul-2025 0133 (EPT)	RTO	6.3
12-Nov-2021 1325 (EPT)	RTO	12.1	07-Nov-2023 1619 (EPT)	RTO	5.4	06-Aug-2025 1849 (EPT)	MAD	7.9
30-Nov-2021 0540 (EPT)	RTO	9.6	10-Nov-2023 0621 (EPT)	RTO	8.1	14-Aug-2025 1740 (EPT)	RTO	4.3
30-Nov-2021 0957 (EPT)	RTO	8.4	15-Dec-2023 0041 (EPT)	RTO	12.3	15-Aug-2025 1533 (EPT)	RTO	5.4
08-Dec-2021 0504 (EPT)	RTO	7.8	19-Dec-2023 0951 (EPT)	RTO	6.5	04-Sep-2025 1956 (EPT)	RTO	9.0
						25-Sep-2025 1912 (EPT)	RTO	10.7
						25-Sep-2025 1935 (EPT)	RTO	7.7
						29-Sep-2025 2130 (EPT)	RTO	6.8

Figure 10-21 shows spin event durations over the past 4 years. Some events last longer than 30 minutes. Beyond 30 minutes, reserves no longer have an obligation to perform. It is not clear what resources are instructed or expected to do after the 30-minute performance obligation. This ambiguity applies to three synchronized reserve events during Winter Storm Elliott in December 2022, which all lasted longer than 30 minutes.

Figure 10-21 Synchronized reserve events duration distribution curve: January 2022 through September 2025



Nonsynchronized Reserve

Nonsynchronized reserve consists of MW available within 10 minutes but not synchronized to the grid. Startup time for nonsynchronized reserve resources is not subject to testing and is based on the parameters in the energy offers submitted by resource owners. There is no defined requirement for nonsynchronized reserve; it is available to economically meet the primary reserve requirement. Generation resources that have designated their entire output as emergency are not eligible to provide nonsynchronized reserves. Generation resources that are not available to provide energy are not eligible to provide nonsynchronized reserves.

The nonsynchronized reserve market has a day-ahead and a real-time component. There are no lost opportunity costs for nonsynchronized reserve. Offline units cannot be dispatched to provide energy, because PJM has not called them to come online, so they do not have a lost opportunity to provide energy. As a result, the supply curve for nonsynchronized reserve has a price of zero and there are no uplift credits paid when LMP is higher than the incremental cost of nonsynchronized reserve units.

PJM defines the demand curve for nonsynchronized reserve, and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less. Since nonsynchronized reserve is considered a lower quality product than synchronized reserve, its clearing price is less than or equal to the synchronized reserve market clearing price. In most market intervals, under usual circumstances, the nonsynchronized reserve market clearing price (NSRMCP) is $0 per MWh. However, due to PJM's increase of the synchronized reserve reliability requirement, there has been an increase in the number of intervals with non-zero NSRMCPs. For example, in 2024, over 60 percent of intervals had a non-zero NSRMCP. Table 10-26 shows the number of intervals with non-zero NSRMCPs in the first nine months of 2025.

PJM uses nonsynchronized reserve when PJM calls nonsynchronized reserve events and when PJM calls specific nonsynchronized reserve resources to respond to synchronized reserve events. There were no nonsynchronized reserve events in the first nine months of 2025.

Market Structure

Demand

There is no explicit demand for nonsynchronized reserve beyond a more general demand for primary reserve, which can be satisfied by the synchronized and nonsynchronized reserve products, and for 30-minute reserve, which can be satisfied by all three reserve products. Beyond the synchronized reserve requirement, the balance of primary reserve can be made up by the economic combination of synchronized and nonsynchronized reserve. While it can be used to satisfy the 30-minute reserve requirement, as seen in Figure 10-2, nonsynchronized reserve is mainly used for satisfying the primary reserve requirement.

In the RTO Reserve Zone, in the first nine months of 2025, the average amount of real-time cleared nonsynchronized reserve was 909.9 MW and the average day-ahead cleared nonsynchronized reserve was 998.6 MW. In the MAD Reserve Subzone, in the first nine months of 2025, the average real-time cleared nonsynchronized reserve was 595.8 MW and the average day-ahead cleared nonsynchronized reserve was 477.0 MW.

Supply

The market solution considers the available supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have made themselves unavailable or have defined themselves to be emergency only are not considered. Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, and combustion turbines and RICE generators that can start in 10 minutes or less.

The available reserve MW for nonsynchronized reserve units is the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. Hydroelectric resources must separately specify their availability and offer MW.

In the first nine months of 2025, an average of 909.9 MW of nonsynchronized reserve were cleared per five-minute interval out of an average eligible and available 1,039.6 MW as part of the primary reserve requirement in the RTO Reserve Zone. Figure 10-22 shows daily average total nonsynchronized reserve MW available in the first nine months of 2025. Available MW decreased in March due to several larger units having planned outages. Daily average available MW increased in May due to greater availability of hydro and RICE generators. Daily average available MW decreased in late June on hot weather days, for which PJM issued 78 intervals with shortage pricing for primary reserve in the RTO and 23 intervals with shortage pricing for 30-minute reserve in the RTO.

Figure 10-22 Daily Average Available Nonsynchronized Reserve: January through September, 2025

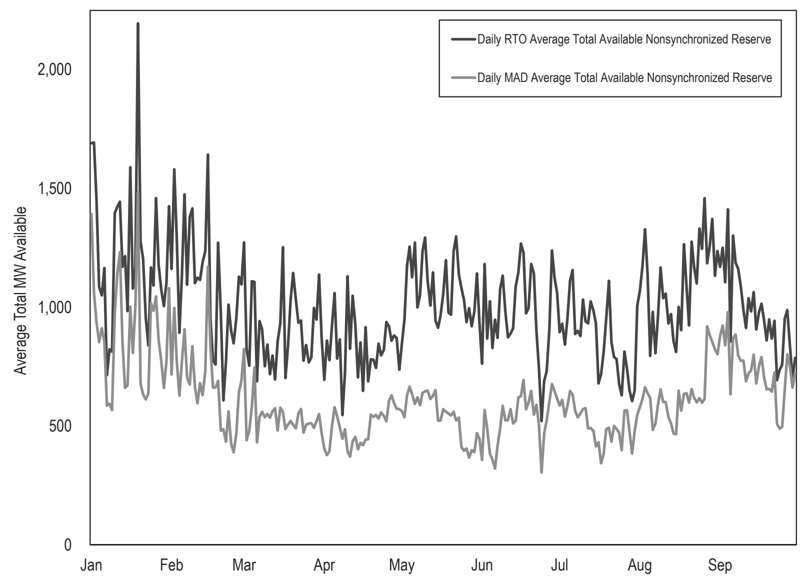
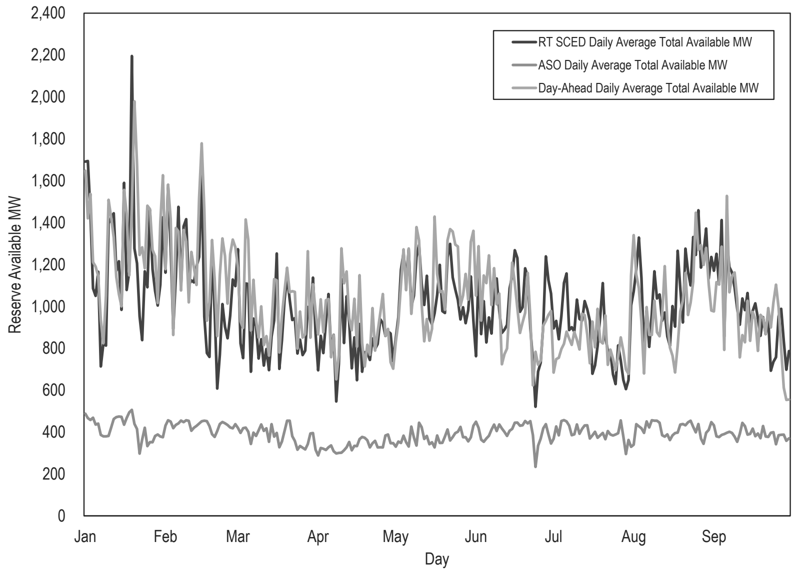


Figure 10-23 shows the daily average total available NSR MW in the ASO, RT SCED, and day-ahead solutions. The available MW in the ASO are consistently lower due to differences in the available MW from flexible units based on the goal of the ASO. For example, a unit could be projected to be online by the ASO but actually be offline in real time.

Figure 10-23 Daily average total available MW in the day-ahead, ASO, and RT SCED solutions: January through September, 2025



Market Behavior

The offer price for nonsynchronized reserve for all resources is cost based, which is $0 per MWh for all resources.

Market Performance

The settled price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the MAD Reserve Subzone. Figure 10-24 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average credited MW for the RTO Reserve Zone. In the first nine months of 2025, the real-time weighted average NSRMCP for all intervals in the RTO Reserve Zone was $1.87 per MWh and the real-time average nonsynchronized reserve cleared was 909.9 MW. The day-ahead weighted average NSRMCP for all intervals in the RTO Reserve Zone was $2.42 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 998.6 MW. The real-time weighted average NSRMCP for all intervals in the MAD Reserve Subzone was $2.22 per MWh and the real-time average nonsynchronized reserve cleared was 595.8 MW. The day-ahead weighted average NSRMCP for all intervals in the MAD Reserve Subzone was $3.43 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 477.0 MW.

Shortage pricing was used in the RTO Reserve Zone for primary reserve on February 11, March 12, March 18, March 19, April 8, May 8, June 22 through June 25, July 8, July 15, July 28, August 14, August 14, September 1, September 4, and September 25, 2025. Shortage pricing was used in the MAD Reserve Subzone for primary reserve on April 8, June 22, and June 24, 2025. The shortage pricing on February 11, June 22, August 14, September 4, and September 15, 2025 overlapped with synchronized reserve events. Conservative operations due to cold weather were in place from January 20 through January 23 and from February 16 through February 19, 2025. Cold weather alerts were issued for January 8 through January 10, January 14 through January 16, January 20 through January 23, February 17 through February 18, and February 19, 2025. Hot weather alerts were issued for May 1, June 22, June 26, July 6, July 7, July 17, July 23 through July 26, and July 28 through July 30, 2025. During most of these short intervals, there was not a true shortage, as PJM still cleared above the average reserve requirements used before PJM's mid-May 2023 increase.

Figure 10-24 Daily weighted average RTO Zone nonsynchronized reserve market clearing price, average MW purchased, and average percent of PR that is NSR: January 2024 through September 2025

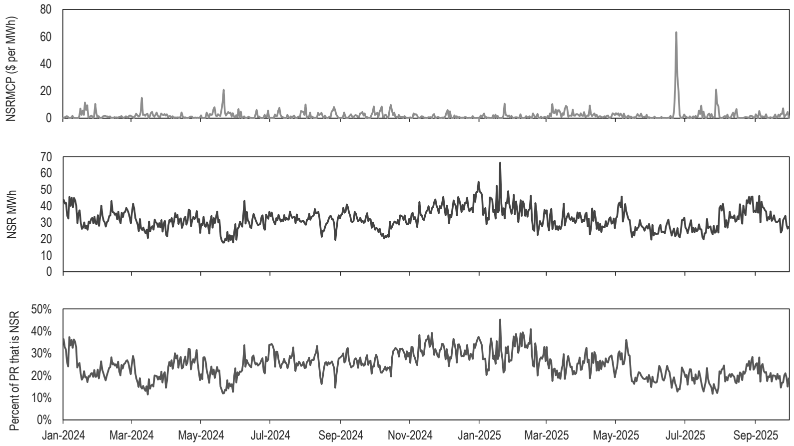


Table 10-26 shows the number of five-minute intervals with an NSRMCP above $0 per MWh. The NSRMCP is equal to the cost of the marginal primary reserve resource.[94] While the offer price of NSR resources is cost based and therefore $0 per MWh, if the marginal resource of primary reserve in an interval is an SR resource with a nonzero cost, then the NSRMCP in that interval will also be nonzero. While the real-time market clears resources in five-minute intervals, the day-ahead market clears by hour, equivalent to blocks of 12 five-minute intervals. Table 10-26 compares the two markets using five-minute intervals. There were 78,612 five-minute intervals in the first nine months of 2025.

Table 10-26 Number of five minute intervals with NSRMCP above $0 per MWh: January through September, 2025

Location	Market	Number of Intervals Where NSRMCP Above $0 per MWh	Percent of Intervals Where NSRMCP Above $0 per MWh
RTO	RT	8,551	10.9%
RTO	DA	23,328	29.7%
MAD	RT	8,680	11.0%
MAD	DA	24,252	30.9%

Figure 10-25 shows the number of intervals per day for which a nonzero NSRMCP equaled the SRMCP. Since the increase to the reserve requirement on May 12, 2023, the average number of such intervals per day has increased, with the maximum number and given number of such intervals per day both trending upwards. In January 2025 and February 2025, the number of such intervals per day decreased, because the number of intervals with a nonzero SRMCP decreased due to the expected value of the SR penalty decreasing to $0 per MWh (Figure 10-12), resulting in lower SR offer prices. However, in March 2025, PJM cleared more SR MW due to a decrease in available NSR MW (Figure 10-2), raising SRMCPs. In the first nine months of 2025, the number of such intervals differed for the RTO Reserve Zone and the MAD Reserve Subzone from January 4 through January 5. Table 10-27 shows a summary of the intervals for which a nonzero NSRMCP did not equal the SRMCP.

94 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.5.2 Determination of Non-Synchronized Reserve Clearing Prices, Rev. 134 (Apr. 23, 2025).

Figure 10-25 Number of intervals per day for which a nonzero NSRMCP equaled the SRMCP: January 2024 through September 2025

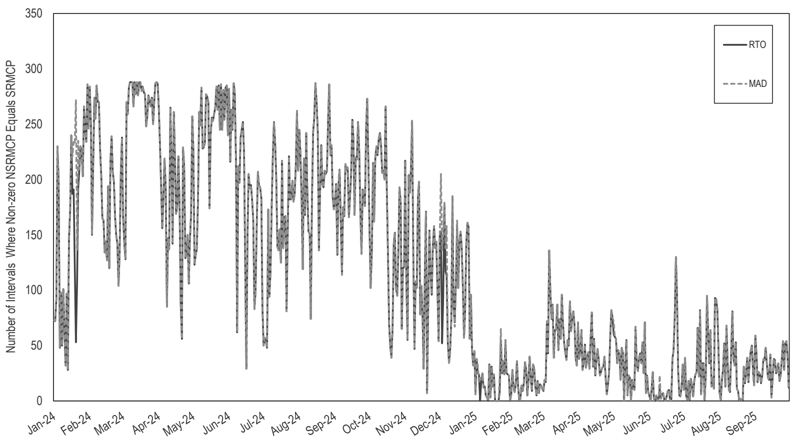


Table 10-27 Intervals with a nonzero NSRMCP in which the NSRMCP did not equal the SRMCP: January through September, 2025

	Intervals where NSRMCP differs from SRMCP		Average Absolute MCP Difference	
Day	RTO	MAD	RTO	MAD
3-Jan-2025	0	4	NA	$6.43
4-Jan-2025	0	42	NA	$9.89
5-Jan-2025	0	10	NA	$20.32
11-Feb-2025	1	1	$300.00	$600.00
15-Mar-2025	2	2	$300.00	$300.00
8-Apr-2025	3	3	$850.00	$425.00
1-May-2025	0	2	NA	$73.05
22-May-2025	0	1	NA	$5.79
22-Jun-2025	3	3	$735.54	$535.54
23-Jun-2025	10	10	$326.07	$326.07
24-Jun-2025	11	11	$321.84	$324.19
1-Jul-2025	0	1	NA	$1.11
28-Jul-2025	2	2	$63.14	$63.14
4-Sep-2025	1	1	$850.00	$550.00

Table 10-28 shows the effect of fast start pricing on the nonsynchronized reserve market's monthly weighted average market clearing price since October 2022. Fast start pricing increases LMP in the pricing run relative to the dispatch run, which increases reserve prices. Fast start pricing also reduces the amount of reserves available in the pricing run compared to the dispatch run, by pretending that fast start units can be dispatched for energy below their economic minimum output limit but not counting MW below the eco min as reserves. For the real-time market, these are the LPC prices weighted by the RT SCED MW. For the day-ahead values, these are the DA prices weighted by the DA dispatch MW. The weighted average market clearing price for each month tends to be higher in the pricing run than in the dispatch run. In the first nine months of 2025, the real-time RTO weighted average price of the pricing run was 42.3 percent higher than that of the dispatch run. In the first nine months of 2025, the day-ahead RTO weighted average price of the pricing run was 8.5 percent lower than that of the dispatch run. In the first nine months of 2025, the real-time MAD weighted average price of the pricing run was 37.9 percent higher than that of the dispatch run. In the first nine months of 2025, the day-ahead MAD weighted average price of the pricing run was 7.5 percent lower than that of the dispatch run.

Table 10-28 Comparison of fast start and dispatch RTO pricing: January 2024 through September 2025

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2024	Jan	$0.48	$0.49	$0.01	1.4%	$1.13	$1.38	$0.26	22.6%
2024	Feb	$0.48	$0.48	$0.00	0.3%	$0.58	$0.81	$0.23	40.4%
2024	Mar	$1.57	$1.58	$0.01	0.7%	$1.71	$2.43	$0.72	42.1%
2024	Apr	$2.77	$2.79	$0.02	0.6%	$0.47	$0.73	$0.26	54.1%
2024	May	$2.09	$2.09	($0.00)	(0.2%)	$2.00	$3.12	$1.13	56.5%
2024	Jun	$1.11	$1.19	$0.08	7.1%	$1.11	$1.26	$0.15	13.6%
2024	Jul	$1.56	$1.68	$0.11	7.4%	$1.32	$1.65	$0.32	24.6%
2024	Aug	$1.19	$1.25	$0.06	5.0%	$1.66	$1.99	$0.32	19.4%
2024	Sep	$1.39	$1.44	$0.06	4.1%	$1.31	$1.77	$0.46	35.5%
2024	Oct	$1.75	$1.78	$0.02	1.4%	$1.89	$2.31	$0.42	22.5%
2024	Nov	$0.88	$0.90	$0.02	2.4%	$0.43	$0.80	$0.37	85.8%
2024	Dec	$0.39	$0.40	$0.01	3.3%	$0.36	$0.48	$0.12	33.3%
2024	All	$1.20	$1.24	$0.03	2.7%	$1.11	$1.48	$0.37	33.1%
2025	Jan	$1.23	$1.30	$0.07	6.1%	$0.70	$0.92	$0.22	31.7%
2025	Feb	$0.59	$0.59	($0.00)	(0.7%)	$0.51	$0.79	$0.28	54.2%
2025	Mar	$3.27	$3.00	($0.26)	(8.1%)	$2.20	$3.41	$1.21	55.1%
2025	Apr	$3.56	$3.41	($0.15)	(4.2%)	$0.93	$1.85	$0.92	99.5%
2025	May	$1.89	$1.77	($0.12)	(6.4%)	$1.11	$1.55	$0.44	39.8%
2025	Jun	$3.74	$3.47	($0.27)	(7.1%)	$3.31	$4.10	$0.79	23.8%
2025	Jul	$6.12	$5.56	($0.56)	(9.2%)	$1.81	$2.66	$0.85	47.2%
2025	Aug	$1.89	$1.59	($0.30)	(15.8%)	$0.78	$1.10	$0.33	42.3%
2025	Sep	$2.52	$1.92	($0.60)	(23.7%)	$1.36	$1.70	$0.34	25.1%
2025	All	$2.57	$2.35	($0.22)	(8.5%)	$1.33	$1.89	$0.56	42.3%

Table 10-29 Comparison of fast start and dispatch MAD pricing: January 2024 through September 2025

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2024	Jan	$0.67	$0.68	$0.01	1.1%	$2.09	$2.46	$0.36	17.4%
2024	Feb	$0.51	$0.51	$0.00	0.3%	$0.72	$1.01	$0.29	40.9%
2024	Mar	$1.78	$1.79	$0.01	0.8%	$1.98	$2.82	$0.84	42.4%
2024	Apr	$3.16	$3.18	$0.02	0.6%	$0.58	$0.87	$0.29	49.5%
2024	May	$2.12	$2.11	($0.01)	(0.3%)	$2.07	$3.27	$1.20	57.9%
2024	Jun	$1.23	$1.26	$0.04	2.9%	$1.25	$1.41	$0.16	13.1%
2024	Jul	$1.82	$1.93	$0.11	5.9%	$1.43	$1.78	$0.35	24.3%
2024	Aug	$1.32	$1.38	$0.06	4.5%	$1.90	$2.27	$0.38	19.9%
2024	Sep	$1.46	$1.51	$0.05	3.4%	$1.46	$1.98	$0.52	35.4%
2024	Oct	$2.36	$2.39	$0.03	1.3%	$2.12	$2.58	$0.46	21.7%
2024	Nov	$1.20	$1.23	$0.03	2.4%	$0.51	$0.90	$0.39	75.7%
2024	Dec	$0.95	$0.96	$0.01	1.3%	$0.96	$1.11	$0.15	15.7%
2024	All	$1.47	$1.50	$0.03	2.0%	$1.38	$1.80	$0.42	30.5%
2025	Jan	$1.09	$1.14	$0.05	4.9%	$1.01	$1.25	$0.23	22.9%
2025	Feb	$1.24	$1.23	($0.01)	(1.1%)	$0.60	$0.94	$0.34	56.1%
2025	Mar	$4.53	$4.21	($0.33)	(7.2%)	$2.71	$4.14	$1.43	52.9%
2025	Apr	$6.57	$6.38	($0.19)	(3.0%)	$1.30	$2.37	$1.07	81.8%
2025	May	$4.13	$3.87	($0.26)	(6.4%)	$1.42	$2.04	$0.61	43.1%
2025	Jun	$7.22	$6.76	($0.46)	(6.4%)	$4.28	$4.91	$0.62	14.5%
2025	Jul	$10.23	$9.40	($0.83)	(8.1%)	$1.88	$2.80	$0.92	49.2%
2025	Aug	$3.34	$2.82	($0.52)	(15.5%)	$0.82	$1.25	$0.44	53.3%
2025	Sep	$2.74	$2.22	($0.52)	(19.0%)	$1.60	$1.96	$0.36	22.5%
2025	All	$3.71	$3.43	($0.28)	(7.5%)	$1.63	$2.25	$0.62	37.9%

In the first nine months of 2025, in the RTO Reserve Zone, the real-time weighted average price of nonsynchronized reserve was $1.87 per MWh and the real-time weighted average sum of the MCP credits and LOC credits for nonsynchronized reserve was $1.86 per MWh. In the first nine months of 2025, in the MAD Reserve Subzone, the real-time weighted average price of nonsynchronized reserve was $2.22 per MWh and the real-time weighted average sum of the MCP credits and LOC credits for nonsynchronized reserve was $2.39 per MWh.

Table 10-30 shows the total nonsynchronized reserve payments by month from January 2024 through September 2025. In June 2025, shortage pricing for primary reserve in the RTO was used for 78 intervals during a hot weather event. In July 2025, shortage pricing for primary reserve in the RTO was used for 16 intervals during a second hot weather event. Figure 10-24 shows the resulting spike in prices. Due to units buying back portions of their day-ahead schedule at these high real-time prices, the sum of the real-time and balancing MCP credits seen in Table 10-30 for June 2025 is significantly negative.

Table 10-30 Total nonsynchronized reserve payments and charges by month: January 2024 through September 2025

Year	Month	Day-Ahead Credits	Real-Time and Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
2024	Jan	$549,761	($805,570)	$246,452	NA	($9,357)
2024	Feb	$406,207	($224,893)	$144,292	NA	$325,606
2024	Mar	$907,106	($493,717)	$265,668	NA	$679,056
2024	Apr	$1,854,995	($145,771)	$81,932	NA	$1,791,156
2024	May	$1,236,498	($655,115)	$575,064	NA	$1,156,446
2024	Jun	$879,638	($184,066)	$41,825	NA	$737,397
2024	Jul	$1,271,008	($182,792)	$42,317	NA	$1,130,532
2024	Aug	$952,433	($144,541)	$71,568	NA	$879,460
2024	Sep	$1,072,480	($401,629)	$266,892	NA	$937,744
2024	Oct	$1,038,044	($141,440)	$157,319	NA	$1,053,924
2024	Nov	$695,733	($35,597)	$74,836	NA	$734,972
2024	Dec	$694,695	($60,267)	$93,644	NA	$728,073
2024	All	$11,558,598	($3,475,398)	$2,061,810	NA	$10,145,009
2025	Jan	$1,310,758	($807,014)	$185,652	NA	$689,396
2025	Feb	$698,931	($300,892)	$96,940	NA	$494,978
2025	Mar	$2,079,574	($470,698)	$289,300	NA	$1,898,176
2025	Apr	$1,984,502	($247,956)	$91,497	NA	$1,828,043
2025	May	$1,340,915	($151,404)	$64,475	NA	$1,253,986
2025	Jun	$2,457,199	($2,281,783)	$102,702	NA	$278,118
2025	Jul	$3,413,482	($954,968)	$121,292	NA	$2,579,806
2025	Aug	$1,266,236	($425,763)	$67,415	NA	$907,888
2025	Sep	$1,261,458	($283,100)	$163,072	NA	$1,141,430
2025	All	$15,813,056	($5,923,579)	$1,182,344	NA	$11,071,821

Table 10-31 provides the day-ahead and real-time nonsynchronized reserve by primary resource type and fuel type for January through September, 2025. Much of the negative balancing MCP credits applied to hydro resources occurred during the polar vortex in January and the hot weather event in June.

Table 10-31 Day-ahead and real-time nonsynchronized reserve by primary resource type and fuel type: January through September, 2025

Resource / Fuel Type	Day-Ahead MWh	Real-Time Scheduled MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Oil	2,117,117	2,086,412	$10,508,597	($1,707,852)	$45,349	$8,846,094
RICE - Natural Gas	607,613	473,985	$1,173,618	($463,364)	$90,012	$800,266
Hydro	3,770,151	3,371,307	$3,960,369	($3,720,750)	$1,043,923	$1,283,541
Other	47,087	28,830	$170,472	($31,613)	$3,060	$141,919

30-Minute Reserve

The 30-minute reserve service is provided by resources that can respond in 30 minutes. The requirement for the 30-minute reserve service can be satisfied by the primary reserve product and the secondary reserve product. There is no NERC standard for 30-minute reserve.

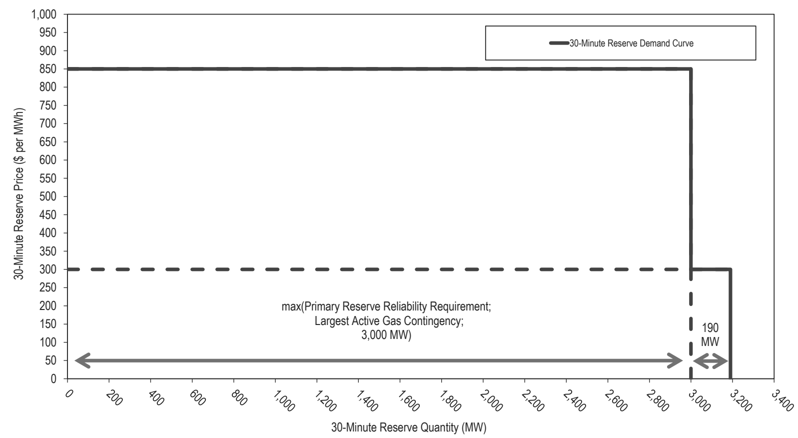
Market Structure

Demand

Demand for the 30-minute reserve service comes from the 30-minute reserve requirement. By default, the 30-minute reserve requirement is equal to the extended reserve requirement plus the 30-minute reserve reliability requirement. The 30-minute reserve reliability requirement is equal to the maximum of: the primary reserve reliability requirement; the largest active gas contingency; and 3,000 MW.[95] Unlike with synchronized reserve and primary reserve, PJM does not model a 30-minute reserve requirement for the defined reserve subzone.[96] However, PJM has the option to define a subzone natural gas contingency reserve requirement using 30-minute reserves. PJM did not exercise this option in the first nine months of 2025.

Figure 10-26 shows an example ORDC for 30-minute reserve for when the primary reserve reliability requirement and the largest active gas contingency are both less than 3,000 MW, and when the extended reserve requirement is equal to its base value of 190 MW. Since the increase to the synchronized reserve reliability requirement in May 2023, the 30-minute reserve requirement has frequently equaled the primary reserve requirement.

Figure 10-26 An example of a 30-minute reserve real-time operating reserve demand curve, including the permanent second step



In the first nine months of 2025, the real-time average 30-minute requirement was 3,519.5 MW and the day-ahead average 30-minute requirement was 3,508.8 MW (Figure 10-4).

Supply

The supply of 30-minute reserves includes all reserves that can convert to energy in 30 minutes. All reserve products can participate in the 30-minute reserve service. In the first nine months of 2025, the demand for 30-minute

95 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 134 (Apr. 23, 2025).
96 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.1 Locational Aspect of Reserves, Rev. 134 (Apr. 23, 2025).

reserve was satisfied by primary reserves (made of synchronized reserves and nonsynchronized reserves) and secondary reserves. The 30-minute reserve requirement is met from the least expensive combination of synchronized, nonsynchronized, and secondary reserves that satisfies the requirements of the synchronized, primary, and 30-minute reserve services (Table 10-9).

Market Concentration

Table 10-32 shows the average HHI of the 30-minute reserve market, including synchronized, nonsynchronized, and secondary reserves, and the percent of intervals for which the maximum market share is above 20 percent. In the first nine months of 2025, the RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market.

Table 10-32 PJM 30-minute reserve market HHI: January through September, 2025

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	869	46.2%	Unconcentrated
RTO	DA	857	54.4%	Unconcentrated

Market Performance

Due to the large amount of available secondary reserve, most 30-minute reserve is procured at low cost, with the amount of cleared secondary reserve far exceeding what is strictly needed to satisfy the 30-minute reserve requirement (Figure 10-2). In the 2025 polar vortex, at the point of lowest amount of cleared 30-minute reserve (January 22 at 8:50, see Figure 10-27), there were still thousands of MW available above the requirement (Figure 10-28).

Figure 10-27 Cleared reserves during the 2025 polar vortex: January 17 through January 26, 2025

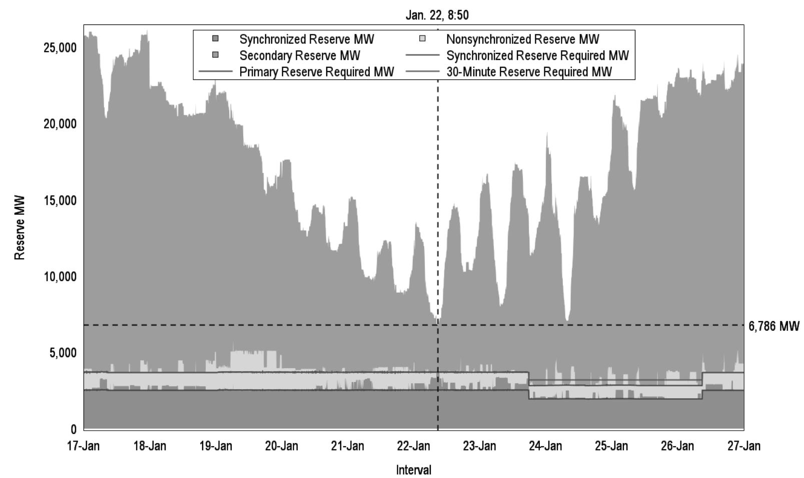
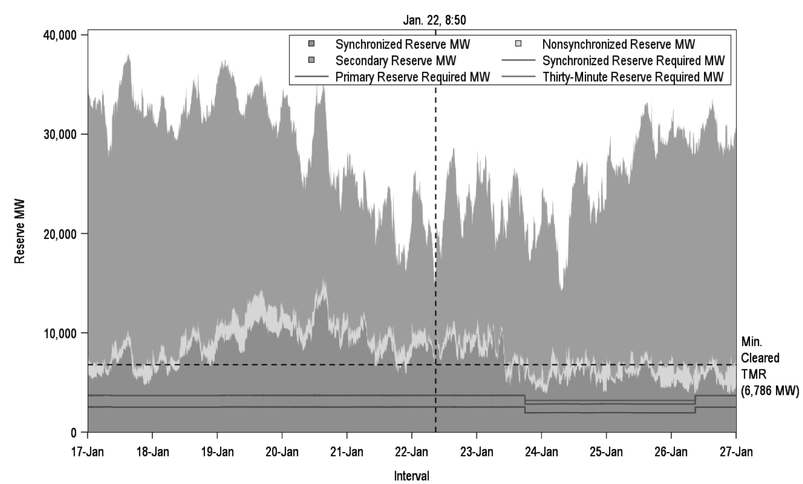
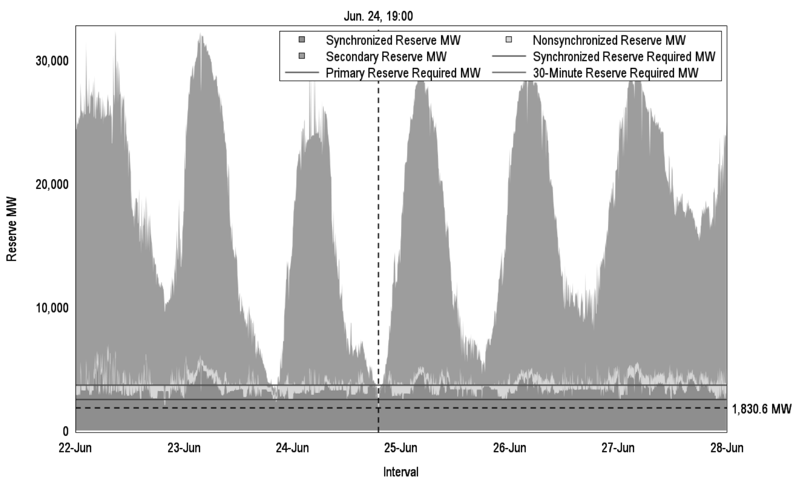


Figure 10-28 Available reserves during the 2025 polar vortex: January 17 through January 26, 2025



However, 30-minute reserves were short in 23 intervals from June 23, 2025, through June 24, 2025, during a hot weather event. Figure 10-29 shows the point during the hot weather event when cleared 30-minute reserves were at their lowest. For that interval, the amount of secondary reserve offered was 5,954.9 MW. This was larger than the 30-minute requirement of 3,677.6 MW.

Figure 10-29 Cleared reserves during the June 2025 hot weather event: June 22 through June 27, 2025



Secondary Reserve

PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 10 to 30 minutes. There is no NERC standard for secondary reserve. The secondary reserve product can only be used to satisfy the 30-minute reserve requirement, and is cleared for five-minute intervals in the real–time market and hourly intervals in the day–ahead market. Failure to convert offline secondary reserves to energy at PJM's request results in a shortfall charge.

Unlike synchronized reserves and nonsynchronized reserves, there is no "event" process to deploy secondary reserves. Instead, PJM uses secondary reserve via the normal energy commitment and dispatch process.

Market Structure

Demand

There is no explicit demand for secondary reserve beyond a more general demand for 30-minute reserve, which can be satisfied by the synchronized, nonsynchronized, and secondary reserve products. Beyond the primary reserve requirement, the balance of 30-minute reserve can be made up by the economic combination of synchronized, nonsynchronized, and secondary reserve.

When the secondary reserve market clearing price is $0 per MWh, PJM's clearing engines clear all available secondary reserve MW. Because of the large amount of secondary reserve cleared, most 30-minute reserve is secondary reserve and most cleared secondary reserve is cleared well in excess of the 30-minute reserve requirement (Figure 10-2).

Supply

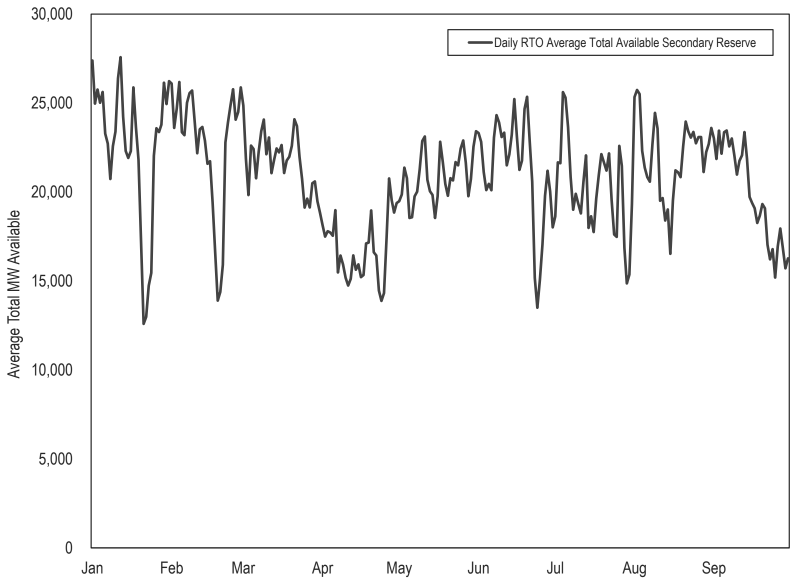
Secondary reserves are reserves that can convert to energy within 10 to 30 minutes. This includes the unloaded capacity of online generation that can be achieved according to the resource ramp rates in 10 to 30 minutes. It also includes offline resources that offer a time to start of less than 30 minutes but more than 10 minutes. Secondary reserves do not include pre-emergency or emergency demand response resources, even if they offer to start in less than 30 minutes. Secondary reserves do not include exports that can be recalled in less than 30 minutes.

As with the other reserve products, for most resources, PJM determines the MW available for secondary reserve based on energy offer parameters.[97] Energy storage resources, hydroelectric resources, and demand response resources must specify their availability and MW separately. Online resources' secondary reserves are based on ramp rates and the lesser of the secondary reserve maximum or economic maximum parameters, as well as any cleared synchronized reserve.[98] The use of the secondary reserve maximum output limit requires prior approval by PJM.[99] Offline resources' secondary reserves are based on the time to start, which is the start-up time plus notification time, and any cleared nonsynchronized reserve.[100] Certain resource types, including nuclear, wind, and solar units, are by default excluded from providing secondary reserves.

Figure 10-30 shows the daily average total available secondary reserve in the first nine months of 2025. In the first nine months of 2025, the real-time average supply of secondary reserve was 21,163.8 MW and the day-ahead average supply was 12,402.1 MW. The available secondary reserve decreased in January during the 2025 polar vortex (Figure 10-28) as PJM brought on more units for energy. The available secondary reserve decreased in February during conservative operations. Secondary reserve decreased in late June during a hot weather event as PJM brought on more units for energy and in late July during a second hot weather event on July 28 through July 30, for which PJM issued hot weather alerts and maximum emergency generation alerts.

97 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 134 (Apr. 23, 2025).
98 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.1 Reserve Market Capability for Online Generation Resources, Rev. 134 (Apr. 23, 2025).
99 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 134 (Apr. 23, 2025).
100 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.2 Reserve Market Capability for Offline Generation Resources, Rev. 134 (Apr. 23, 2025).

Figure 10-30 Daily Average Available Secondary Reserve: January through September, 2025



Market Behavior

For all resources, the secondary reserve offer price is $0 per MWh.[101] For online resources, the energy market opportunity cost is calculated by PJM based on market prices.

101 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 134 (Apr. 23, 2025).

Market Performance

Figure 10-31 shows the unweighted average market clearing prices for secondary reserves in the first nine months of 2025. Due to the product's low cost and ample supply, the secondary reserve market clearing price is almost always $0 per MWh. In the first nine months of 2025, the real-time SecRMCP was nonzero for 32 five-minute intervals and the day-ahead SecRMCP was nonzero for zero hours. These nonzero real-time intervals were the result of shortage pricing on June 23 and June 24, during a hot weather event. For June 23 and June 24, PJM issued Maximum Generation alerts. Maximum generation alerts in July during a second hot weather event did not happen similar price spikes.

Figure 10-31 Secondary reserve prices: January through September, 2025

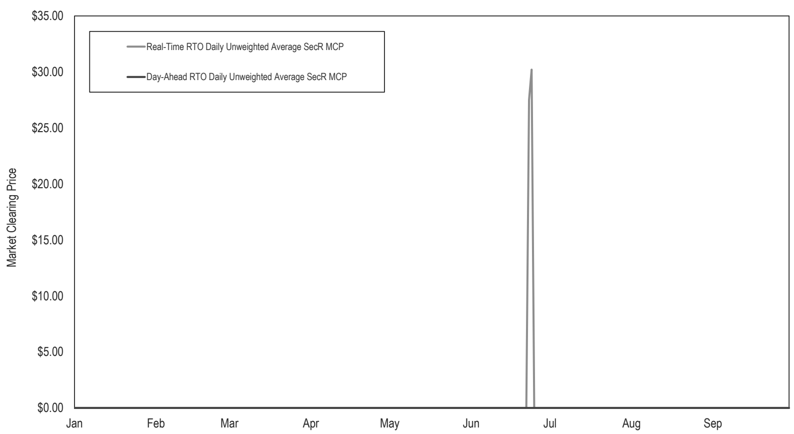


Table 10-33 compares the dispatch run and pricing run market clearing prices for the day-ahead and real-time secondary reserve markets. For both the dispatch run and the pricing run, the real-time values are the LPC prices for each run weighted by the RT SCED MW. For the day-ahead values, these are the DA prices weighted by the DA dispatch MW. In the first nine months of 2025, the day-ahead prices of secondary reserve were always $0 per MWh in both the pricing run and the dispatch run. In real time, the pricing run and dispatch run were nonzero for 32 five-minute intervals from June 23 through June 24, in which shortage pricing was used for 30-minute reserve.

Table 10-33 Comparison of fast start and dispatch pricing components: January 2024 through September 2025

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2024	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Apr	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	May	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Jun	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Jul	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Aug	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Sep	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Oct	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Nov	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Dec	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	All	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Apr	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	May	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Jun	$0.00	$0.00	$0.00	NA	$0.05	$0.05	$0.00	0.0%
2025	Jul	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Aug	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Sep	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	All	$0.00	$0.00	$0.00	NA	$0.01	$0.01	$0.00	0.0%

Table 10-34 shows the day-ahead credits, balancing market credits, LOC credits, and effective shortfall charges for secondary reserves from January 2024 through September 2025.[102] In the first nine months of 2025, the real-time weighted average secondary reserve market clearing price was $0.01 per MWh and the day-ahead weighted average secondary reserve market clearing price was $0.00 per MWh. In the first nine months of 2025, the real-time weighted average credit per MWh, considering the total credits paid and the capped MWh, was $0.05 per MWh and the day-ahead weighted average credit was $0.00 per MWh.

Table 10-34 Monthly secondary reserve settlements: January 2024 through September 2025

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Effective Shortfall Charge	Total Credits
2024	Jan	$0	$0	$158,524	$0	$158,524
2024	Feb	$0	$0	$96,091	$0	$96,091
2024	Mar	$0	$0	$129,812	$0	$129,812
2024	Apr	$0	$0	$96,526	$0	$96,526
2024	May	$0	$0	$289,740	$0	$289,740
2024	Jun	$0	$0	$123,403	$0	$123,403
2024	Jul	$0	$0	$311,806	$0	$311,806
2024	Aug	$0	$0	$395,574	$0	$395,574
2024	Sep	$0	$0	$113,597	$0	$113,597
2024	Oct	$0	$0	$360,577	$0	$360,577
2024	Nov	$0	$0	$45,400	$0	$45,400
2024	Dec	$0	$0	$137,850	$0	$137,850
2024	All	$0	$0	$2,258,901	$0	$2,258,901
2025	Jan	$0	$0	$244,917	$0	$244,917
2025	Feb	$0	$0	$142,489	$0	$142,489
2025	Mar	$0	$0	$132,092	$0	$132,092
2025	Apr	$0	$0	$135,333	$0	$135,333
2025	May	$0	$0	$420,010	$0	$420,010
2025	Jun	$0	($955,594)	$1,903,795	$0	$948,201
2025	Jul	$0	$0	$1,353,451	$0	$1,353,451
2025	Aug	$0	$0	$1,390,735	$0	$1,390,735
2025	Sep	$0	$0	$851,060	$0	$851,060
2025	All	$0	($955,594)	$6,573,881	$0	$5,618,287

Table 10-35 provides secondary reserve credits by primary resource and fuel type for the first nine months of 2025.

Table 10-35 Secondary reserve credits by primary resource and fuel type: January through September, 2025

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Combined Cycle	80,799	3,499,524	$0	$52,449	$1,768,954	$1,821,403
CT - Natural Gas	64,645,628	92,958,574	$0	($389,137)	$2,678,079	$2,288,942
CT - Oil	11,789,817	12,806,146	$0	($927,861)	$188,010	($739,851)
Hydro	365	1,604,720	$0	$213,120	$18,900	$232,020
RICE - Natural Gas	124,848	106,311	$0	$0	$14,350	$14,350
RICE - Oil	657,985	745,239	$0	($41,409)	$24,599	($16,809)
RICE - Other	6,857	129,022	$0	$15,447	$106,900	$122,348
Steam - Coal	38,239	2,894,271	$0	$2,771	$1,258,902	$1,261,673
Steam - Other	16	892	$0	$0	$15,160	$15,160
Other	144,501	32,010	$714,603	$0	$119,026	$500,024

Among other reasons, a secondary reserve resource is paid an LOC credit when PJM determines that the resource was backed down in order to clear more secondary reserve. Because the supply of secondary reserves greatly exceeds the amount needed to meet the 30-minute reserve requirement, PJM does not actually back down resources to clear more secondary reserve. However, because of the method used by PJM to determine whether a resource was backed down, PJM at times pays resources for an incorrectly determined real-time opportunity cost. For example, PJM erroneously treated resources coming online to provide energy as having been backed down to provide secondary reserves. PJM does not back down resources below their economic minimum to provide secondary reserves, but in the first nine months of 2025, for secondary reserve resources that did not clear day-ahead and were generating below their economic minimum points, PJM paid $2,095,647 in LOC credits.

102 Unlike synchronized reserve, for secondary reserve, shortfall is accounted for in the balancing MCP credits and is not a separate item. The effective shortfall charge is the real-time SecR MCP multiplied by the shortfall MW, a value used when calculating the balancing MCP credits.

Regulation Market

Regulation matches generation with short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single real-time market.

PJM filed proposed significant changes to the regulation market design with FERC on April 16, 2024.[103] The Commission Order of June 14, 2024, accepted the PJM proposal as filed. PJM will implement the changes to the regulation market in two phases.[104] Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The proposed Phase 1 changes will eliminate many of the significant issues identified by the MMU that have resulted from a two product, two signal market design including the incorrect and inconsistent use and application of the MBF/MRTS.

This report analyzes the current (as of the third quarter of 2025) regulation market design and results during the first nine months of 2025.

Market Design

PJM's regulation market design is a result of Order No. 755.[105] The objective of PJM's regulation market design should be to minimize the cost to provide regulation using two resource types in a single market.

The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). RegA is PJM's slow oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, with slower ramp rates. RegD is PJM's fast oscillation regulation signal and is designed for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour.

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor (MBF) and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

The goal of the regulation market solution should be to meet the regulation requirement with the least cost combination of RegA and RegD. When solving for the least cost combination of RegA and RegD MW to meet the regulation requirement, the regulation market will substitute RegD MW for RegA MW when RegD is cheaper. Performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service. All resource MW (RegA and RegD) are converted into effective MW. RegA MW are converted into effective MW by multiplying the RegA MW offered by their performance score. RegD MW are converted into effective MW by multiplying the RegD offered by their performance score and by the MBF. The regulation requirement is defined as the total effective MW required to provide a defined amount of area control error (ACE) control.

The regulation market converts performance adjusted RegD MW into effective MW using the MBF in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per effective MW.

The marginal rate of technical substitution (MRTS) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying a defined regulation requirement at feasible combinations of RegA and RegD MW. While resources following RegA and RegD can both provide regulation service in PJM's Regulation Market, PJM's joint optimization is intended to

103 PJM, "Regulation Market Design Filing," Docket No. ER24-1772-000.
104 See 187 FERC ¶ 61,173.
105 See Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW using the RegD offer and the MBF associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to effective MW is equal to the MRTS associated with that RegA/RegD combination.

For example, a 1.0 MW RegD resource with a total offer price of $2 per MW with a MBF of 0.5 and a performance score of 100 percent would be calculated as offering 0.5 effective MW (0.5 MBF times 1.00 performance score times 1 MW). The total offer price would be $4 per effective MW ($2 per MW offer divided by the 0.5 effective MW).

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[106] Performance scores are reported on an hourly basis for each resource.

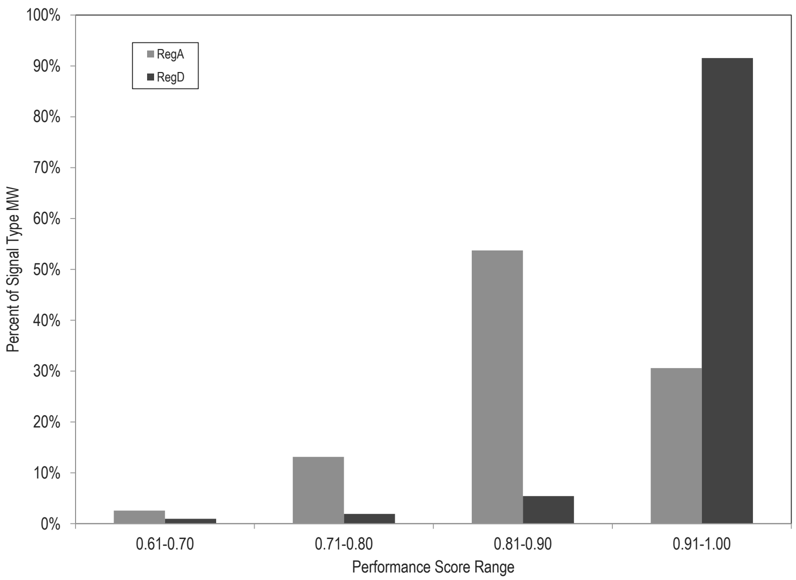
Table 10-36 and Figure 10-32 show the average performance score by resource type and the signal followed in the first nine months of 2025. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[107] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-32 shows, 91.5 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 30.6 percent of RegA resources had average performance scores within that range in the first nine months of 2025. In the first nine months of 2024, 73.9 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 22.0 percent of RegA resources had average performance scores within that range.

106 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 54 (July Dec. 17, 2024).
107 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Table 10-36 Hourly average performance score by unit type: January through September, 2025

		Performance Score Range			
		61-70	71-80	81-90	91-100
RegA	Battery	0.0%	0.0%	62.7%	37.3%
	CT	0.0%	6.3%	67.8%	25.9%
	Diesel	0.0%	0.0%	1.8%	98.2%
	DSR	0.0%	71.8%	26.5%	1.7%
	Hydro	0.0%	0.1%	51.4%	48.5%
	Steam	4.3%	20.6%	55.3%	19.8%
RegD	Battery	1.1%	0.3%	4.2%	94.2%
	CT	36.6%	34.2%	0.0%	29.2%
	Diesel	0.0%	0.0%	34.5%	65.5%
	DSR	0.2%	8.7%	10.6%	80.5%
	Hydro	-	-	-	-
	Steam	-	-	-	-

Figure 10-32 Hourly average performance score by regulation signal type: January through September, 2025



Each cleared resource in a class (RegA or RegD) is allocated a portion of the class signal (RegA or RegD). This portion of the class signal is based on the cleared regulation MW of the resource relative to the cleared MW for that class. This signal is called the Total Regulation Signal (TREG) for the resource. A resource that cleared 10 MW of capability (AREG) will be provided a percentage TREG signal asking for a positive or negative regulation movement between negative and positive 100 percent (10 MW) around its regulation set point.

The MMU identified an issue with the current method of calculating the regulation performance score of a resource. The issue is that the delay and correlation components of the performance score do not accurately reflect how well a unit is responding to the regulation signal. These delay and correlation components can remain high, even when a unit is responding poorly to the regulation signal, and artificially inflate the overall performance score of the unit. For example, during the Winter Storm Elliott event, several units were not able to maintain their response to the regulation signal. These units received a precision score of zero, however, their delay and accuracy scores were near perfect (>0.95). This resulted in several units receiving regulation credits because their overall performance score was approximately 0.65 (each component of the performance score has an equal 1/3 weighting) despite not actually providing regulation. To address this issue, the MMU has proposed to evaluate regulation performance using a precision based performance score, which would only depend on the difference between the regulation signal and the unit's response to that signal.

$$Performance\ Score_{10Sec} = 1 - ABS\left(\frac{RegOutputMW - SignalMW}{AReg}\right)$$

With the total performance score for the clearing interval being the average of each 10 second performance score. This means that, in a simplified 10 second interval, a unit that cleared 10 MW (AREG = 10 MW) responding with a steady 7.5 MW (75 percent of their total capability) to a positive pegged signal (Signal MW = 10; TREG = 100 percent) would logically receive a performance score of 0.75. The MMU presented this recommendation to the regulation market senior task force.

PJM's proposed solution evaluates the 10 second error in a unit's output based on the average regulation signal MW during the entire clearing interval.[108]

$$Performance\ Score_{10Sec} = 1 - ABS\left[\frac{(RegOutputMW - SignalMW)}{\left(\frac{ClearingIntervalAvgSignal + AReg}{2}\right)}\right]$$

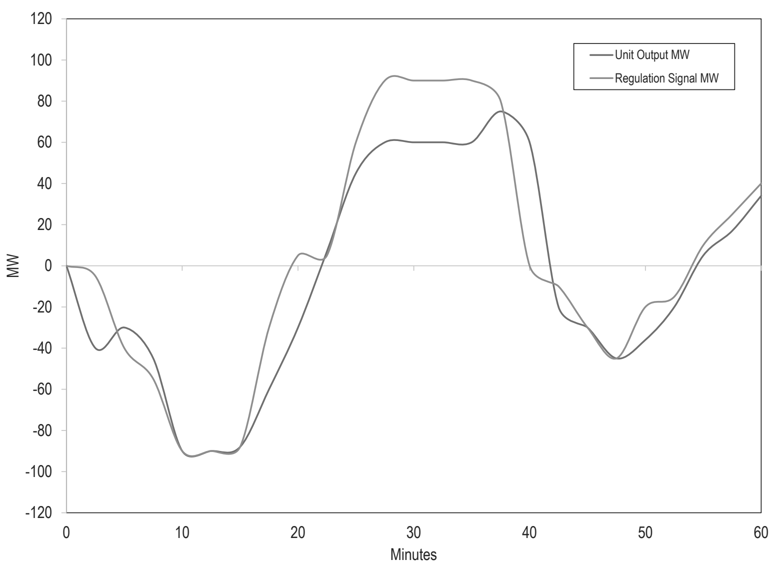
This has the effect of scaling each 10 second performance score based on the clearing interval average of the overall regulation signal. Using this equation in the simplified case above would yield a performance score equal to 0.75

108 The current regulation clearing interval is one hour. The proposed change is to move to a 30 minute clearing interval.

only if the clearing interval average signal is pegged, and less than 0.75 when the clearing interval average signal is close to zero.

Figure 10-33 illustrates an example unit that cleared 100 MW of regulation, following the regulation signal for one hour. Based on the MMU's proposed performance score calculation, the unit would have a performance score of 0.8450 for the hour. Using PJM's proposed calculation, that same unit would have a performance score of only 0.6981 for the hour because the clearing interval average signal is small (2.7 MW). If both the regulation signal and the unit's response in this example were shifted up (or down) by 10 MW, the MMU's result would remain the same, because it only depends on the response of the unit to the signal it is supposed to follow. The PJM result however, would change to 0.7249 because the clearing interval average signal would increase to 12.7 MW. PJM's calculation would lead to different results, based solely on the overall clearing interval average of the regulation signal; identical unit performance would yield different performance score results.

Figure 10-33 A example unit providing 100 MW of regulation while following an almost neutral regulation signal



Resources are paid Regulation Market Clearing Price (RMCP) credits and lost opportunity cost credits, which are uplift payments. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference. PJM posts clearing prices for the regulation market (RMCCP, RMPCP and RMCP) in dollars per effective MW. The regulation market clearing price (RMCP in $/effective MW) for the hour is the simple average of the 12 five minute RMCPs within the hour. The RMCP is set in each five minute interval based on the marginal offer in each interval. The performance clearing price (RMPCP in $/effective MW) is based on the marginal performance offer (RMPCP) for the hour. The capability clearing price (RMCCP in $/effective MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour. This is done so the total of RMPCP plus RMCCP equals the total clearing price (RMCP) but the RMPCP is maximized.

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED) solving every 15 minutes; and the real-time security constrained economic dispatch market solution (RT SCED) solving approximately every five minutes. The market clearing price is determined by pricing software (LPC) that looks at the units cleared in the most recently approved RT SCED case, approximately 10 minutes ahead of the target solution time. The marginal prices assigned by the LPC to five minute intervals are averaged over the hour for an hourly regulation market clearing price.

Market Design Issues

PJM's current regulation market design is severely flawed and is not efficient or competitive. The market results do not represent the least cost solution for the defined level of regulation service.

In a well functioning market, every resource should be paid the same clearing price per unit produced. That is not true in the PJM Regulation Market. RegA and RegD resources are not paid the same clearing price in dollars per effective MW. RegD resources are being paid more than the market clearing price. This flaw in the market design has caused operational issues, has caused over investment in RegD resources.

If all MW of regulation were treated the same in both the clearing of the market and in settlements, many of the issues in the PJM Regulation Market would be resolved. However, the current PJM rules result in the payment to RegD resources being up to 1,000 times the correct price.

RegA and RegD have different physical capabilities. In order to permit RegA and RegD to compete in the single PJM Regulation Market, RegD must be translated into the same units as RegA. One MW of RegA is one effective MW. The translation is done using the marginal benefit factor (MBF). As more RegD is added to the market, the relative value of RegD declines, based on its actual performance attributes. For example, if the MBF is 0.001, a MW of RegD is worth 0.001 MW of RegA (or 1/1,000 of a MW of RegA). This is the same thing as saying that 1.0 MW of RegD is equal to 0.001 effective MW when the MBF is 0.001.

Almost all of the issues in PJM's Regulation Market are caused by the inconsistent application of the MBF. Because the MBF is not included in settlements, when the MBF is less than 1.0, RegD resources are paid too much. When the MBF is less than 1.0, each MW of RegD is worth less than 1.0 MW of RegA. The market design buys the correct amount of RegD, but pays RegD as if the MBF were 1.0. In an extreme case, when the MBF is 0.001, RegD MW are paid 1,000 times too much. If the market clearing price is $1.00 per MW of RegA, RegD is paid $1,000 per effective MW. Resolution of this problem requires that PJM pay RegD for the same effective MW it provides in regulation, 0.001 MW.

To address the identified market flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the proposal finding it inconsistent with Order No. 755.

The MBF related issues with the regulation market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial solution to the RegD over procurement problem which was implemented on December 14, 2015. The interim solution was designed to reduce the relative value of RegD MW in all hours and to cap purchases of RegD MW during critical performance hours. But the interim solution did not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Additional changes were implemented on January 9, 2017. These modifications included changing the definition of off peak and on peak hours, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15 minute neutrality requirement of the RegD signal to a 30 minute neutrality requirement.

The January 9, 2017, design changes appear to have been intended to make RegD more valuable. That is not a reasonable design goal. The design goal should be to determine the least cost way to provide needed regulation. The RegA signal is now slower than it was previously, which may make RegA following resources less useful as ACE control. RegA is now explicitly used to support the conditional energy neutrality of RegD. The RegD signal is now the difference between ACE and RegA. RegA is required to offset RegD when RegD moves in the opposite direction of that required by ACE control in order to permit RegD to recharge. These changes in the signal design will allow PJM to accommodate more RegD in its market solutions. The new signal design is not making the most efficient use of RegA and RegD resources. The explicit reliance on RegA to offset issues with RegD is a significant conceptual change to the design that is inconsistent with the long term design goal for regulation. PJM increased the regulation requirement as part of these changes.

The January 9, 2017, design changes replaced off peak and on peak hours with nonramp and ramp hours with definitions that vary by season. The regulation requirement for ramp hours was increased from 700 MW to 800 MW (Table 10-37). These market changes did not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Table 10-37 Seasonal regulation requirement definitions[109]

Season	Dates	Nonramp Hours	Ramp Hours
Winter	Dec 1 - Feb 28(29)	00:00 - 03:59 09:00 - 15:59	04:00 - 08:59 16:00 - 23:59
Spring	Mar 1 - May 31	00:00 - 04:59 08:00 - 16:59	05:00 - 07:59 17:00 - 23:59
Summer	Jun 1 - Aug 31	00:00 - 04:59 14:00 - 17:59	05:00 - 13:59 18:00 - 23:59
Fall	Sep 1 - Nov 30	00:00 - 04:59 08:00 - 16:59	05:00 - 07:59 17:00 - 23:59

Performance Scores

Performance scores, by class and unit, are not an indicator of how well resources contribute to ACE control. Performance scores are an indicator only of how well the resources follow their TREG signal. High performance scores with poor signal design are not a meaningful measure of performance. For example, if ACE indicates the need for more regulation but RegD resources have provided all their available energy, the RegD regulation signal will be in the opposite direction of what is needed to control ACE. So, despite moving in the wrong direction for ACE control, RegD resources would get a good performance score for following the RegD signal and will be paid for moving in the wrong direction.

The RegD signal prior to January 9, 2017, is an example of a signal that resulted in high performance scores, but due to 15 minute energy neutrality built into the signal, ran counter to ACE control at times. Energy neutrality means that energy produced equals energy used within a defined timeframe. With 15 minute energy neutrality, if a battery were following the regulation signal to provide MWh for 7.5 minutes, it would have to consume the same amount of MWh for the next 7.5 minutes. When neutrality correction of the RegD signal is triggered, it overrides ACE control in favor of achieving zero net energy over the 15 minute period. When this occurs, the RegD signal runs counter to the control of ACE and hurts rather than helps ACE. In that situation, the control of ACE, which must also offset the negative impacts of RegD, depends entirely on RegA resources following the RegA signal. High performance scores under the signal design prior to January 9, 2017, was not an indication of good ACE control.

The January 9, 2017, design changes did not address the fundamental issues with the definition of performance or the nature of payments for performance in the regulation market design. The regulation signal should not be designed to favor a particular technology. The signal should be designed to result in the lowest cost of regulation to the market. Only with a performance score based on full substitutability among resource types should payments be based on following the signal. The MRTS must be redesigned to reflect the actual capabilities of technologies to provide regulation. The PJM regulation market design remains fundamentally flawed.

In addition, the absence of a performance penalty, imposed as a reduction in performance score and/or as a forfeiture of revenues, for deselection initiated by the resource owner within the hour, creates a possible gaming opportunity for resources which may overstate their capability to follow the regulation signal. The MMU recommends that there be a penalty enforced as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming.

Battery Settlement

The change from 15 to 30 minute signal neutrality, implemented in the January 9, 2017, design changes, resulted in the reduction of performance scores for short duration batteries. In April 2017, several participants filed a complaint against PJM, asserting that these changes discriminated against their battery units.[110] The MMU objected to the complaints. Despite the unsupported assertions in the complaint, PJM settled with the participants. The settlement was approved by FERC on April 7, 2020.[111] Table 10-38 shows the battery units that are part of the settlement. Starting July 1, 2020, the affected battery units began receiving compensation based on the greater of

109 See PJM, "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

110 See FERC Docket Nos. EL17-64-000 and EL17-65-000.

111 See 170 FERC ¶ 61,258 (2020).

their current performance score, or their rolling average actual hourly performance score for the last 100 hours the resource operated prior to the January 9, 2017, implementation of the 30-minute conditional neutrality.

In addition to paying uneconomic regulation credits based on inflated performance scores, the settlement also required that the affected battery units be cleared in the regulation market regardless of whether their offer was economic. As long as the settlement batteries were offered as either self scheduled with a zero offer, or as a zero priced offer, they must be cleared despite the fact that these units would not necessarily have cleared based on economics.[112] In order to comply with this condition, PJM cleared additional MW beyond what was needed for the regulation requirement in cases where the settlement battery units did not clear but met the offer rules of the settlement. This resulted in excess charges to customers for regulation service.

The total additional regulation credits received as a result of the settlement, as well as the additional regulation MW cleared as a result of the settlement, from July 2020 through December 2023, are shown in Table 10-39. From July 2020 through December 2023, the battery settlement provided $5.6 million in excess regulation credits, and resulted in 32,536.1 MW of additional cleared regulation. The term of the settlement was for 42 months, and ended December 31, 2023.

Table 10-38 Batteries in settlement

Parent Company	Unit	MW	Status
The AES Corporation	Laurel Mountain	32.0	Retired
	Warrior Run	10.0	Retired
Energy Capital Partners, LLC	Hazel	20.0	Active
Galt Power, Inc.	Trent	4.0	Retired
	McHenry	20.0	Active
	Beckjord 1	2.0	Active
	Beckjord 2	2.0	Active
Invenergy, LLC	Beech Ridge	31.5	Active
	Grand Ridge 6	4.5	Retired
	Grand Ridge 7	31.5	Active
NextEra Energy, Inc.	Lee Dekalb	20.0	Active
	Garrett	10.4	Active
	Meyersdale	18.0	Active
	Mantua Creek	2.0	Active
Renewable Energy Systems Holdings, LTD	Joliet	20.0	Retired
	West Chicago	20.0	Retired
Sumitomo Corporation	Willey	6.0	Retired

112 See *id.* at P 17.

Table 10-39 Total excess regulation credits received and monthly additional MW cleared due to battery settlement: July 2020 through December 2023

		Battery Settlement Impact	
Year	Month	Regulation Credit ($)	Additional Cleared Regulation MW
2020	Jul	$56,031	171.2
	Aug	$42,673	233.1
	Sep	$33,153	535.2
	Oct	$70,934	631.7
	Nov	$63,252	603.3
	Dec	$70,873	1,127.3
	Total	$336,917	3,301.7
2021	Jan	$90,139	3,149.4
	Feb	$107,544	1,727.7
	Mar	$113,896	3,192.6
	Apr	$140,436	4,872.3
	May	$183,125	7,718.7
	Jun	$62,989	147.4
	Jul	$78,109	26.3
	Aug	$136,571	8.5
	Sep	$113,884	26.9
	Oct	$190,648	1,046.2
	Nov	$226,473	238.7
	Dec	$119,035	4.9
	Total	$1,562,848	22,159.4
2022	Jan	$234,340	54.5
	Feb	$94,937	384.3
	Mar	$114,254	833.3
	Apr	$129,724	24.7
	May	$108,873	78.9
	Jun	$180,607	33.5
	Jul	$170,781	240.9
	Aug	$227,416	234.9
	Sep	$183,432	182.8
	Oct	$149,534	133.1
	Nov	$86,040	83.1
	Dec	$665,772	105.2
	Total	$2,345,711	2,389.1
2023	Jan	$94,110	47.5
	Feb	$78,473	122.7
	Mar	$89,127	334.9
	Apr	$152,817	1,548.2
	May	$134,084	201.3
	Jun	$126,184	267.5
	Jul	$130,840	187.9
	Aug	$109,813	118.2
	Sep	$131,305	1,183.1
	Oct	$146,004	313.5
	Nov	$93,332	241.6
	Dec	$82,918	119.6
	Total	$1,369,008	4,685.8
Total		$5,614,484	32,536.1

Regulation Signal

As with any signal design for substitutable resources, the MBF function should be determined by the ability of RegA and RegD resources to follow their signals, including conditions under which neutrality cannot be maintained by RegD resources. The ability of energy limited RegD to provide ACE control depends on the availability of excess RegA capability to support RegD under the conditional neutrality design. When RegD resources are largely energy limited resources, a correctly calculated MBF would exhibit a rapid decrease in the MBF value for every MW of RegD added. The result is that only a small amount of energy limited RegD is economic. The current and proposed signals and corresponding MBF functions do not reflect these principles or the actual substitutability of resource types.

Through the ongoing stakeholder regulation task force, the MMU has proposed several changes to address the current issues with the regulation signal market design. The MMU proposes that the two signals be combined into one, simplified regulation signal. All units would be cleared based on their total performance adjusted offers, with performance scores used as a tie breaker for equal offers (the status quo). Performance scores would be modified to only include a precision score. The move to a single signal would also eliminate the 30-minute signal neutrality but the regulation market clearing period would be shortened from one hour to 30 minutes. This would allow units with issues providing for a full hour to leave the market if needed without the regulation signal being tailored to uneconomically accommodate specific unit types.

Marginal Benefit Factor Issues

The MBF function, as implemented in the PJM Regulation Market, is not equal to the MRTS between RegA and RegD. The MBF is not consistently applied throughout the market design, from optimization to settlement, and market clearing does not confirm that the resulting combinations of RegA and RegD are realistic and can meet the defined regulation demand. The calculation of total regulation cleared using the MBF is incorrect.[113]

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours, has provided a consistently inefficient market signal to participants regarding the value of RegD in every hour, and has overpaid for RegD. This over procurement has degraded the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

PJM and the MMU filed a joint proposal with FERC on October 17, 2017, to address issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market, but the proposal was rejected by FERC.[114]

Marginal Benefit Factor Not Correctly Defined

The MBF used in the PJM Regulation Market prior to the December 14, 2015, changes did not accurately reflect the MRTS between RegA and RegD resources under the old market design, and it does not accurately reflect the MRTS between RegA and RegD resources under the current design. The MBF function is incorrectly defined and improperly implemented in the current PJM Regulation Market.

The MBF should be the marginal rate of technical substitution between RegA and RegD MW at different, feasible combinations of RegA and RegD that can be used to provide a defined level of regulation service. The objective of the market design is to find, given the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the MBF function is incorrectly defined, or improperly implemented in the market clearing and settlement, the resulting combinations of RegA and RegD will not represent the least cost solution and may not be a feasible way to reach the target level of regulation.

The MBF is not included in PJM's settlement process. This is a design flaw that results in incorrect payments for regulation. The issue results from two FERC orders. From October 1, 2012, through October 31, 2013, PJM implemented a

113 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.

114 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

FERC order that required the MBF to be fixed at 1.0 for settlement calculations only. On October 2, 2013, FERC directed PJM to eliminate the use of the MBF entirely from settlement calculations of the capability and performance credits and replace it with the RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective retroactively to October 1, 2012.[115] That rule continues in effect. The result of the current FERC order is that the MBF is used in market clearing to determine the relative value of an additional MW of RegD, but the MBF is not used in the settlement for RegD.

If the MBF were consistently applied, every resource would receive the same clearing price per marginal effective MW. But the MBF is not consistently applied and resources do not receive the same clearing price per marginal effective MW.

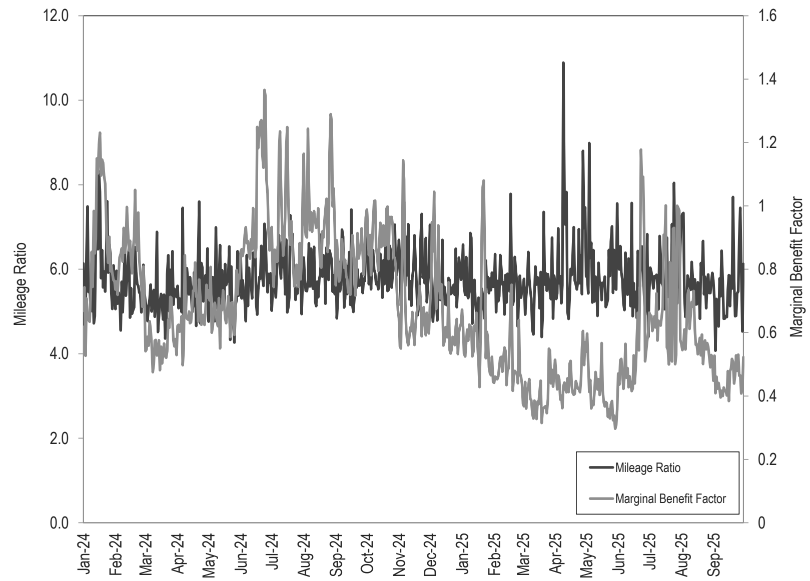
The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the mileage required of RegD resources and changed the energy neutrality component of the signal from a strict 15 minute neutrality to a conditional 30 minute neutrality. The changes in signal design increased the mileage ratio (the ratio of RegD mileage to RegA mileage). In addition, to adapt to the 30 minute neutrality requirement, some RegD resources decreased their offered capability to maintain their performance.

Figure 10-34 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio increased from 5.71 in the first nine months of 2024, to 5.78 in the first nine months of 2025 (an increase of 1.2 percent). The average MBF decreased from 0.82 in the first nine months of 2024, to 0.52 in the first nine months of 2025 (a decrease of 36.1 percent). The high mileage ratios are the result of the mechanics of the mileage ratio calculation. Extreme mileage ratios result when the RegA signal is fixed at a single value (pegged) to control ACE and the RegD signal is not. If RegA is held at a constant MW output, mileage is zero for RegA. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio is very large.

115 See 145 FERC ¶ 61,011 (2013).

These results are an example of why it is not appropriate to use the mileage ratio, rather than the MBF, to measure the relative value of RegA and RegD resources. In these events, RegA resources are providing ACE control by providing a fixed level of MW output which means zero mileage, while RegD resources alternate between helping and hurting ACE control, both of which result in positive mileage.

Figure 10-34 Daily average MBF and mileage ratio: January 2024 through September 2025



The increase in the average mileage ratio caused by the signal design changes introduced on January 9, 2017, caused a large increase in payments to RegD resources on a performance adjusted MW basis.

Table 10-40 shows RegD resource payments on a performance adjusted actual MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2024, through September 30, 2025. Due to significantly higher LOC as a result of higher LMPs, the average regulation market clearing price in the first nine months of 2025 was $11.12 higher than in the first nine months of 2024 (See Table 10-54.) In the first nine months of 2025, RegD resources earned 17.6 percent more per performance adjusted actual MW than RegA resources (compared to 15.8 percent more in the first nine months of 2024) due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-40 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2024 through September 2025

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($ Performance Adjusted MW)	Percent RegD Overpayment ($/Performance Adjusted MW)
2024	Jan	$42.62	$35.76	19.2%
	Feb	$23.01	$19.04	20.9%
	Mar	$27.25	$22.86	19.2%
	Apr	$24.87	$23.34	6.6%
	May	$40.91	$36.91	10.8%
	Jun	$30.59	$27.62	10.7%
	Jul	$46.18	$39.32	17.5%
	Aug	$33.72	$30.57	10.3%
	Sep	$35.49	$27.58	28.7%
	Oct	$37.74	$33.32	13.3%
	Nov	$32.37	$28.30	14.4%
	Dec	$40.02	$33.56	19.3%
Total		$34.67	$29.94	15.8%
2025	Jan	$70.56	$58.77	20.1%
	Feb	$44.29	$37.04	19.6%
	Mar	$45.69	$36.06	26.7%
	Apr	$32.48	$30.34	7.1%
	May	$33.92	$28.70	18.2%
	Jun	$60.99	$55.09	10.7%
	Jul	$49.16	$42.54	15.6%
	Aug	$35.67	$29.42	21.2%
	Sep	$46.46	$38.64	20.2%
Total		$46.61	$39.63	17.6%

The current settlement process does not result in paying RegA and RegD resources the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the MBF is not used in settlements. Instead of being paid based on the MBF, (RMCCP + RMPCP)*MBF, RegD resources are paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis, unless offset by a low mileage ratio. The average MBF was less than 1.0 in the first nine months of 2025 (0.52).

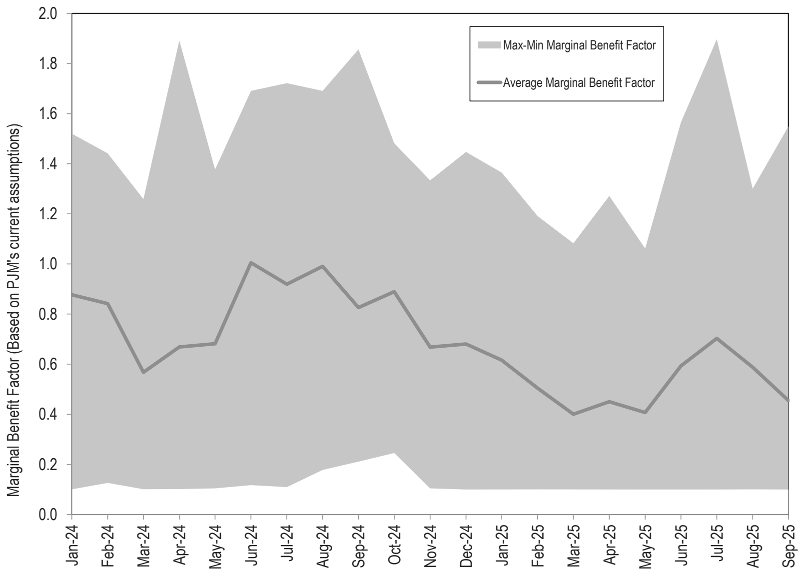
The effect of using the mileage ratio instead of the MBF for purposes of settlement is illustrated in Table 10-41. Table 10-41 shows how much RegD resources are currently being paid, adjusted to a per effective MW basis, on average, in 2024 and the first nine months of 2025 under the current rules, compared to how much RegD resources should have been paid if they were actually paid for effective MW. Using the MBF consistently throughout the PJM regulation market would result in RegA and RegD resources being paid exactly the same on a per effective MW basis. However, the PJM regulation market only uses the MBF in the market clearing and setting of price on a dollar per effective MW basis, it does not use the MBF to convert RegD MW into effective MW for purposes of settlement. Because the MBF is not used to convert RegD MW into effective MW for purposes of settlement, RegD resources are paid the dollar per effective MW price, but this is paid for performance adjusted MW, not for effective MW. This causes the MW value of RegD resources to be inflated in settlement when the MBF is less than one and to be undervalued in settlement when the MBF is greater than one. In the first nine months of 2025, the MBF averaged 0.52, while the average daily mileage ratio was 5.78, resulting in RegD resources being paid $28.9 million more than they would have been paid on an effective MW basis if the MBF were correctly implemented. In the first nine months of 2024, the MBF averaged 0.82, and the average mileage ratio was 5.71, resulting in RegD resources being paid $8.7 million more than they would have been paid if the MBF were correctly implemented.

Table 10-41 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2024 through September 2025

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment ($/Effective MW)	Total RegD Overpayment ($)
2024	Jan	$56.67	$35.76	$35.76	58.4%	$879,903
	Feb	$33.20	$19.04	$19.04	74.4%	$670,940
	Mar	$72.24	$22.86	$22.86	216.0%	$1,774,338
	Apr	$48.61	$23.34	$23.34	108.3%	$915,045
	May	$89.43	$36.91	$36.91	142.3%	$1,898,186
	Jun	$33.39	$27.62	$27.62	20.9%	$64,580
	Jul	$57.63	$39.32	$39.32	46.6%	$956,416
	Aug	$36.83	$30.57	$30.57	20.5%	$146,692
	Sep	$49.28	$27.58	$27.58	78.7%	$1,443,266
	Oct	$42.57	$33.32	$33.32	27.8%	$525,106
	Nov	$66.99	$28.30	$28.30	136.7%	$1,488,457
	Dec	$88.99	$33.56	$33.56	165.1%	$2,038,914
Total		$56.52	$29.94	$29.94	88.8%	$12,801,842
2025	Jan	$160.94	$58.77	$58.77	173.9%	$4,068,755
	Feb	$153.25	$37.04	$37.04	313.8%	$3,633,212
	Mar	$168.78	$36.06	$36.06	368.1%	$4,599,577
	Apr	$113.52	$30.34	$30.34	274.2%	$2,535,632
	May	$127.12	$28.70	$28.70	342.9%	$3,211,473
	Jun	$117.09	$55.09	$55.09	112.5%	$2,154,061
	Jul	$91.70	$42.54	$42.54	115.6%	$2,281,356
	Aug	$82.90	$29.42	$29.42	181.8%	$2,602,939
	Sep	$160.14	$38.64	$38.64	314.4%	$3,775,704
Total		$130.35	$39.63	$39.63	228.9%	$28,862,707

Figure 10-35 shows, the monthly maximum, minimum and average MBF, for January 2024 through September 2025. The average daily MBF in the first nine months of 2025 was 0.52. The average daily MBF in the first nine months of 2024 was 0.82. The bottom of the MBF range results from PJM's administratively defined MBF minimum threshold of 0.1.

Figure 10-35 Maximum, minimum, and average PJM calculated MBF by month: January 2024 through September 2025



The MMU recommends that the regulation market be modified to incorporate a consistent and correct application of the MBF throughout the optimization, assignment and settlement process.[116]

The overpayment of RegD has resulted in offers from RegD resources that are almost all at an effective cost of $0.00 ($0.00 offers plus self scheduled offers). RegD MW providers are ensured that such offers will clear and will be paid a price determined by the offers of RegA resources. This is evidence of the impact of the flaws in the clearing engine and the overpayment of RegD resources on the offer behavior of RegD resources.

Table 10-42 shows, by month, cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for January 2024 through September 2025. In the first nine months of 2025, an average of 74.6 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first nine months of 2024, an average of 92.7 percent of all cleared RegD MW had an effective cost of $0.00. In the first nine months of 2025, an average of 79.7 percent of all RegD offers were self scheduled, compared to an average of 67.2 percent of all RegD offers in the first nine months of 2024.

The high percentage of self scheduled offers is a result of the incentives created by the flaws in the regulation market. Because self scheduled offers are price takers, they are cleared along with the zero cost offers in the market clearing engine. However, unlike zero cost offers, self scheduled offers do not risk having an LOC added to their offer during the market clearing process, ensuring that self scheduled offers have a zero cost during market clearing. Given the increasing saturation of the regulation market with RegD MW, specifically demand response and battery units which do not receive LOC, market participants eligible for LOC that offer at zero instead of self scheduling, run the risk of an LOC added to their offer, and thus not clearing the market.

The average monthly RegD cleared in the market increased 94.6 MW (49.6 percent), from 190.8 MW in the first nine months of 2024 to 285.4 MW in the first nine months of 2025. The average monthly RegD cleared with an effective cost of zero increased 35.7 MW (20.2 percent), from 176.8 MW in the first nine months of 2024 to 212.6 MW in the first nine months of 2025. Self scheduled RegD cleared MW increased 99.7 MW (77.7 percent), from 128.2 MW in the first nine months of 2024 to 227.8 MW in the first nine months of 2025. Average cleared RegD MW with a zero cost offer increased 3.9 MW (8.0 percent), from 48.6 MW in the first nine months of 2024 to 52.6 MW in the first nine months of 2025. Dual offers are not solved correctly in the regulation market clearing engine, and reduce the amount of RegD that

116 See "Regulation Market Review," Operating Committee (May 5, 2015) <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

clears. The decrease of dual offers in the first nine months of 2025 resulted in an increase in average monthly cleared RegD regulation and a decrease in the average monthly MBF seen in Figure 10-35.

Table 10-42 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2024 through September 2025

		Average Performance Adjusted Cleared RegD MW						
Year	Month	$0.00 Offer	$0.00 Offer Percent of Total	Self Scheduled	Self Scheduled Percentage of Total	Total Effective Cost of Zero	Effective Cost of Zero Percentage of Total	Total
2024	Jan	54.5	28.0%	126.2	64.9%	180.7	92.9%	194.5
	Feb	45.5	24.5%	128.6	69.2%	174.1	93.7%	185.9
	Mar	52.0	26.0%	138.1	68.9%	190.1	94.9%	200.3
	Apr	49.3	25.5%	130.4	67.4%	179.8	92.8%	193.6
	May	50.5	26.3%	126.4	65.9%	177.0	92.3%	191.8
	Jun	41.8	22.5%	131.8	70.9%	173.6	93.4%	185.9
	Jul	46.6	23.8%	131.5	67.3%	178.0	91.1%	195.4
	Aug	48.8	26.0%	121.4	64.6%	170.3	90.6%	188.0
	Sep	48.7	26.8%	119.2	65.6%	167.9	92.4%	181.7
	Oct	38.6	21.9%	125.5	71.2%	164.1	93.1%	176.3
	Nov	47.9	24.4%	132.7	67.6%	180.6	92.0%	196.2
	Dec	62.0	30.6%	126.4	62.5%	188.4	93.1%	202.4
Total		48.9	25.6%	128.2	67.1%	177.1	92.7%	191.1
2025	Jan	65.5	26.1%	176.1	70.3%	241.6	96.5%	250.4
	Feb	64.0	22.0%	219.7	75.4%	283.6	97.4%	291.2
	Mar	60.5	20.5%	227.4	77.2%	287.9	97.7%	294.7
	Apr	49.8	18.0%	222.1	80.4%	271.8	98.4%	276.3
	May	45.8	15.6%	242.3	82.8%	288.0	98.4%	292.7
	Jun	44.2	14.7%	247.5	82.3%	291.7	97.0%	300.7
	Jul	43.7	15.0%	243.7	83.9%	287.4	98.9%	290.5
	Aug	47.4	16.5%	239.5	83.3%	286.9	99.8%	287.4
	Sep	52.3	18.4%	232.4	81.6%	284.7	100.0%	284.7
Total		52.5	18.4%	227.9	79.9%	280.3	98.3%	285.3

Incorrect MBF and total effective MW when clearing units with dual product offers

Under PJM market rules, regulation units that have the capability to provide both RegA and RegD MW are permitted to submit an offer for both signal types in the same market hour. While the objective of the PJM market design is to find the least cost combination of RegA and RegD resources to provide the required level of regulation service, the method of clearing the regulation market for an hour in which one or more units has a dual offer is incorrect and leads to solutions that are not the most economic. The result of the flaw is that the MBF in the regulation market clearing phase is incorrectly low compared to the MBF in the market solution phase, too little RegD is cleared relative to the efficient amount, the RegD resources that do clear are underpaid when the resulting MBF is greater than 1.0 and the actual amount of effective MW procured is higher than the regulation requirement.

In order for the clearing engine to provide the correct economic solution when the pool of available resources contains one or more units with dual offers, the calculation would have to be performed iteratively to determine which of the dual offers would provide the least cost solution. But this is not how PJM clears the regulation market when there are dual offer units. PJM rank orders the regulation supply curve by potential effective cost assuming the dual offer resources are available as both RegA and RegD resources simultaneously, and assigns every RegD resource, including dual offer resources, a unit specific benefit factor.

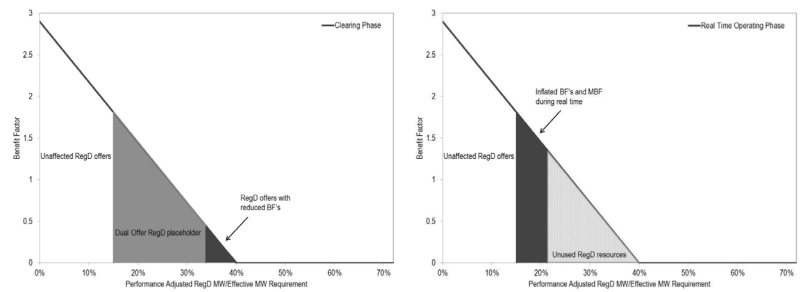
Each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. But PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

During the clearing phase, the MBF of RegD resources is a function of the RegD MW that clear. The MBF for all RegD resources declines as more RegD resources are cleared. Based on this relationship, in the case where a dual offer unit is assigned to be a RegA resource rather than a RegD resource, the MBF of remaining RegD resources in the supply curve should increase. The placeholder RegD MW from the dual offer should be removed, the cleared MW from below the placeholder should be shifted up the supply/MBF curve, and additional RegD MW offers that were pushed below an MBF of zero and initially not included, should be considered. But PJM does not recalculate the MBF values for the remaining RegD resources when determining the cleared effective MW needed to satisfy the regulation requirement during the clearing phase. The result is that the MBF in the clearing phase is incorrectly low, and the actual amount of effective MW procured is higher.

After meeting the target effective MW to satisfy the regulation requirement for that hour through the clearing process, the unit specific benefit factors of those displaced units are recalculated in the real-time operating phase and increased based on their actual contribution. The effective MW contributions of those originally displaced units are correctly calculated in the operating phase, but because the supply for that hour has already been set based on their incorrect effective MW, the solution includes more effective MW than calculated in the clearing phase. As a result, the market solution includes more than the target level of effective MW in the actual operating hour.

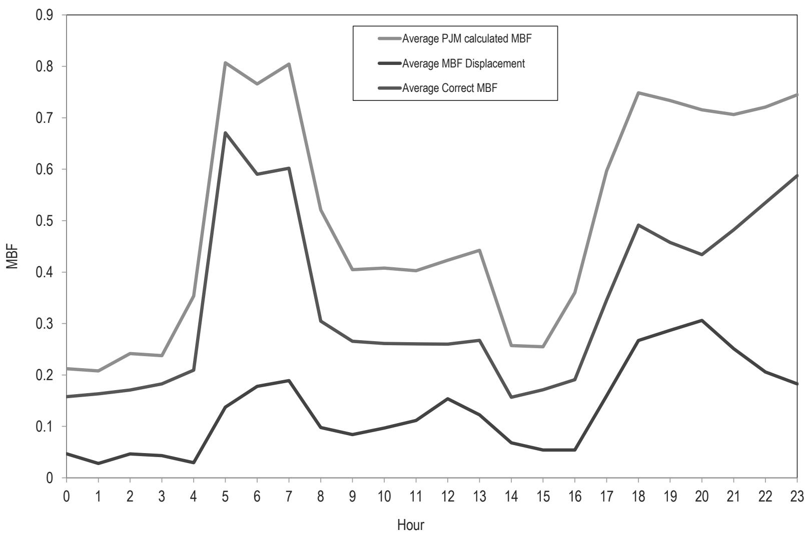
The issue is illustrated in Figure 10-36. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the curve in the clearing phase. The effective MW of the cleared RegD resources with higher effective costs are represented by the blue triangle in the clearing phase. Not shown are additional RegD MW with higher effective costs that were assigned an MBF of 0 and not cleared. The 150 MW dual offer unit is chosen to operate as a RegA resource in the operational hour. As a result, the cleared supply for RegA in the clearing phase is the same RegA supply realized in the real time operating phase. But that is not the case for the RegD supply. Since the supply curve and unit specific benefit factors of RegD MW are not recalculated in the clearing phase after the 150 MW RegD offer is removed, the amount of effective MW realized in the real-time operating phase is inconsistent with the clearing phase. Because the RegD portion of the 150 MW dual offer unit was not chosen to be RegD MW, the RegD resources represented by the blue triangle in the clearing phase will contribute more effective MW (the blue area in the real-time solution phase) in the real-time solution phase than was assumed in the clearing phase because the MBF in the clearing phase was too low. Since the blue area under the curve in the real-time solution phase is greater than the blue area in the clearing phase and the amount of RegA remains the same between the clearing phase and real-time operating phase, the market will have cleared too many effective MW relative to the effective MW requirement. The MBF in the operating phase is higher than if the clearing had been solved correctly.

Figure 10-36 Clearing phase BF/effective MW reduction, real-time BF/ effective MW inflation, and exclusion of available RegD resources



In the first nine months of 2025, 92.2 percent of all hours had at least one unit with a dual offer. In the first nine months of 2025, 64.7 percent of all hours had at least one dual offer unit that was chosen to run as RegA, resulting in an average MBF increase of 0.12 in the operating phase. The average MBF increase due to dual offers clearing as RegA in the first nine months of 2024 was 0.27. If the market had been cleared correctly, the correct average MBF would have been significantly lower in real time (operating phase), because additional RegD offers with lower benefit factors that were initially excluded, would have been included after the removal of the dual offer placeholder, reducing the MBF. Figure 10-37 illustrates the PJM calculated average MBF in real time (operating phase), the average amount the MBF is artificially increased (MBF displacement) due to dual offers clearing as RegA, and what the correct average MBF would have been in each hour of the day for the first nine months of 2025 if the clearing solution were solved correctly.

Figure 10-37 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: January through September, 2025



Absent the ability to correctly clear dual offers, the MMU recommends that the ability of resources to submit dual offers be removed. Under this revision to the rules, resources could offer as either RegA or RegD in a given hour, but not both within the same market hour.

Price Spikes

Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

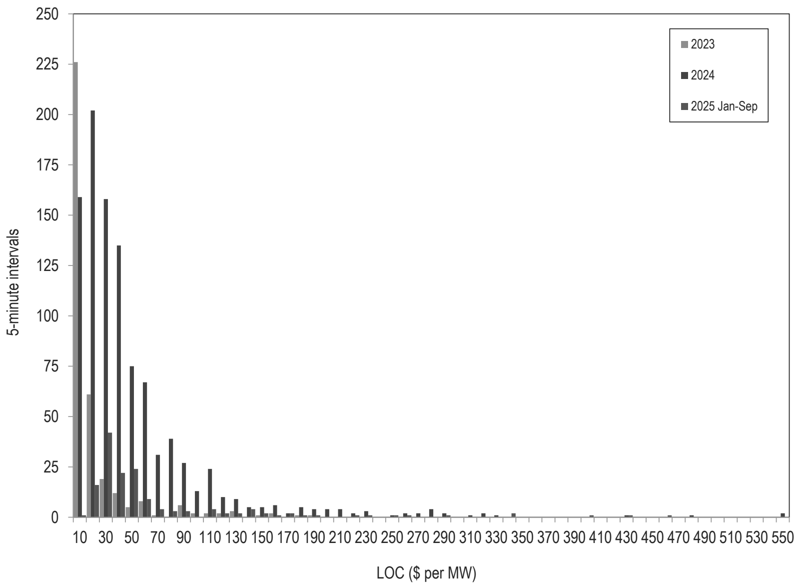
The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate of the adjusted LOC offer component, hour ahead projections of LMPs are used. Units are then cleared based on the sum of each of their hour ahead adjusted offer components. The actual LOC is used to determine the final, actual interval specific all in offer of RegD resources.

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit is less than one (e.g. the marginal unit is a RegD unit), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) and the realized offer price of the resource in the actual market result. This will cause a significant price spike in the regulation market. In cases where the MBF of the marginal resource is very low, such as 0.001, the price spikes can be very significant for a small change between expected and actual LOC. In January 2019, FERC approved PJM's proposal to create a 0.1 floor for the MBF to reduce the occurrence of these price spikes.[117] This change reduced the amount and frequency of the price spikes, but it was not designed to eliminate them and it did not eliminate them.

Figure 10-38 shows the LOC in each five minute interval in which the marginal unit had a unit specific benefit factor less than one (e.g. a RegD unit) and the LOC was greater than zero from 2023 through the first nine months of 2025.

117 See 166 FERC ¶ 61,040 (2019).

Figure 10-38 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2023, 2024, and January through September, 2025



For a RegD resource to clear the regulation market with an MBF of 0.001, the resource's offer, in dollars per marginal effective MW, must be less than or equal to competing offers from RegA MW. A RegD offer of 1 MW with an MBF of 0.001 and a price of $1 per MW, would provide 0.001 effective MW at a price of $1,000 per effective MW. So long as RegA MW are available for less than $1,000 per effective MW, this resource will not clear. The only way for RegD MW to clear to the point where the MBF of the last MW is 0.001, is if the offer price of the relevant resources that clear, including estimated LOC, is $0.00. But, if the same resource(s) has a positive LOC within the hour, based on real-time changes in LMP, the zero priced offer is adjusted to reflect the positive LOC, resulting in an extremely high offer and clearing price for regulation.

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. But, due to the current market design's failure to use the MBF in settlement, RegD is not paid on a dollar per effective MW basis. This disconnect between the process of setting price and the process of paying resources is the primary source of the market failure in PJM's Regulation Market and the cause of the observed price spikes in the regulation market. In the example, the 0.001 MW from the RegD resource should be paid $1,000 times 0.001 MW or $1.00. But the current rules would pay the RegD resource $1,000 times 1.0 MW or $1,000. If the market clearing and the settlements rules were consistent, the incentive for this behavior would be eliminated. The current rules provide a strong incentive for this behavior.

The prices spikes observed in PJM's Regulation Market are a symptom of a market failure in PJM's Regulation Market caused by an inconsistent application of the MBF between market clearing and market settlement. Due to the inconsistent application of the MBF, the current market results are not consistent with a competitive market outcome. In any market, resources should be paid the marginal clearing price for their marginal contribution. In the regulation market, all resources should be paid the marginal clearing price per effective MW and all resources in the regulation market should be paid for each of their effective MW. PJM's Regulation Market does not do this. PJM's market applies the MBF in determining the relative and total value of RegD MW in the market solution for purposes of market clearing and price, but does not apply the same logic in determining the payment of RegD for purposes of settlement. As a result, market prices do not align with payment for contributions to regulation service in market settlements.

The inconsistent application of the MBF in PJM's regulation market design is generating perverse incentives and perverse market results. The price spikes are a symptom of the problem, not the problem itself.

Uplift Calculation Issues

Regulation uplift is calculated by comparing a resource's regulation offer price plus its regulation lost opportunity cost (including shoulder LOC if applicable) adjusted by the performance score, to the clearing price credits the unit received.[118] If the sum of the resource's offer plus LOC is greater than the amount of clearing price credits received, additional uplift credits are given equal to the difference.

The calculation of regulation uplift during settlements for coal and natural gas units is incorrect, and results in the overpayment of uplift.[119] In order to determine the amount of regulation uplift, the difference between the MW output of the unit while it was providing regulation is compared to the desired MW output of the unit if it had not provided regulation. The desired MW output at LMP used in the calculation of regulation uplift during settlements is determined based on a unit's energy offer and the LMP during the interval being evaluated. But this desired MW does not account for the ability of a unit to actually produce the desired output because it ignores the fact that units have a limited physical ability ramp. It does not take into account the ramp rate. This results in the overpayment of uplift by paying for MW that the unit could not have produced given their energy market output at the beginning of the interval and their ramp rate.

Table 10-43 shows the amount of uplift overpayment by fuel type for the first nine months of 2025, as a result of the ramp rate not being used in the current calculation. The overpayments are calculated using a desired MW level that can be achieved in a five minute market interval based on the units' ramp rates. In the first nine months of 2025, overpayments totaled $18.7 million. Coal units received 47.0 percent of the overpayment while providing 5.2 percent of settled regulation MW.

The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW.

118 The clearing price for each interval is set by the marginal unit's total offer (capability and performance offers plus LOC), adjusted by the marginal unit's performance score, and does not include any shoulder LOC.

119 Hydro units operate on a schedule rather than an energy bid, therefore a different equation is used to calculate their regulation LOC and uplift. The issue discussed does not effect that calculation. Also, demand response and battery units do not receive uplift.

Table 10-43 Amount of LOC overpayment: January 2024 through September 2025

		Uplift overpayment		
Year	Month	Coal	Natural Gas	Total
2024	Jan	$1,232,475	$668,296	$1,900,771
	Feb	$776,377	$351,419	$1,127,796
	Mar	$1,004,166	$685,613	$1,689,779
	Apr	$1,554,338	$725,974	$2,280,312
	May	$1,254,186	$954,532	$2,208,717
	Jun	$1,675,670	$636,096	$2,311,766
	Jul	$2,576,400	$674,632	$3,251,032
	Aug	$1,908,099	$496,129	$2,404,228
	Sep	$2,331,876	$1,122,113	$3,453,989
	Oct	$1,008,340	$1,145,836	$2,154,176
	Nov	$1,913,037	$505,352	$2,418,389
	Dec	$1,400,408	$700,542	$2,100,950
	Total	$18,635,373	$8,666,533	$27,301,905
2025	Jan	$1,004,426	$2,185,841	$3,190,267
	Feb	$519,703	$799,643	$1,319,345
	Mar	$1,269,495	$1,911,648	$3,181,143
	Apr	$1,618,508	$861,896	$2,480,405
	May	$837,073	$974,515	$1,811,588
	Jun	$753,845	$996,387	$1,750,233
	Jul	$977,451	$721,631	$1,699,082
	Aug	$775,739	$613,436	$1,389,175
	Sep	$1,037,943	$847,702	$1,885,645
	Total	$8,794,183	$9,912,700	$18,706,883

Market Redesign

PJM proposes to separate the regulation market into two products: one that only needs to respond when the regulation signal is above zero (RegUp), and one that only needs to respond when the regulation signal is below zero (RegDown). This change would also allow units to clear both signals and operate the way they do currently. PJM has not done any systematic testing of the proposal. PJM has not explained what problem this design change is intended to fix, or analyzed what impact this design would have on reliability, or how this will affect the cost of regulation. The MMU recommends a single product market with a single signal.

On June 14, 2024, the FERC approved PJM's proposed market redesign, to be implemented in two phases. Phase one, using one signal and one market price, will go into effect on October 1, 2025, and will implement the proposed changes to the LOC and performance score. Phase two will go into effect on October 1, 2026, and will implement the RegUp and RegDown signal with a separate price for RegUp and for RegDown.[120]

Market Structure

Supply

Table 10-44 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first nine months of 2025.[121] Actual MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and by the resource specific benefit factor to get effective MW. A resource can choose to follow either signal. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the offers from units that are designated as available for the day. These are daily offers that can be modified on an hourly basis up to 65 minutes before the hour.[122] Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

In the first nine months of 2025, the average hourly offered supply of regulation for nonramp hours was 788.7 actual MW (787.2 effective MW). This was an increase of 93.2 actual MW (an increase of 78.9 effective MW) from the first nine months of 2024, when the average hourly offered supply of regulation was 695.5 actual MW (708.3 effective MW). In the first nine months of 2025, the average hourly offered supply of regulation for ramp hours was 1,063.0 actual MW (1,119.1 effective MW). This was an increase of 68.6 actual MW (an increase of 72.1 effective MW) from the first nine months of 2024, when the average hourly offered supply of regulation was 994.4 actual MW (1,047.0 effective MW).[123]

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 1.62 in the first nine months of 2025 (1.45 in the first nine months of 2024). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.54 in the first nine months of 2025 (1.42 in the first nine months of 2024).

Table 10-44 Hourly average actual and effective MW offered and cleared: January through September, 2025[124]

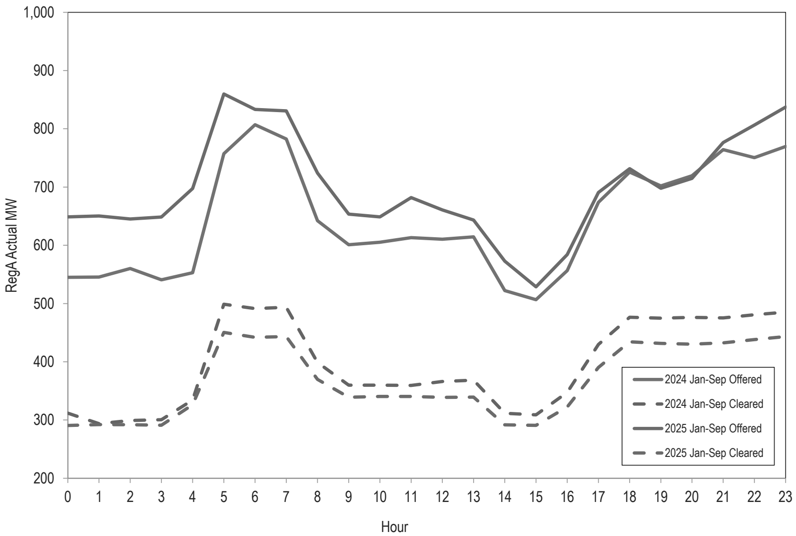
			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,063.0	1,000.5	62.6	800.3	262.8
	Nonramp	788.7	744.7	44.1	580.3	208.4
Effective Offered MW	Ramp	1,119.1	1,032.5	86.6	697.4	421.7
	Nonramp	787.2	728.4	58.8	503.5	283.7
Actual Cleared MW	Ramp	690.7	635.8	54.9	440.8	249.9
	Nonramp	486.7	450.7	36.0	280.4	206.3
Effective Cleared MW	Ramp	800.0	720.6	79.4	385.0	415.0
	Nonramp	526.5	474.3	52.2	243.6	282.9

The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-39. The average hourly offered MW from RegA resources during ramp hours for the first nine months of 2025 was 800.3 actual MW, an increase of 4.3 percent from the first nine months of 2024 (767.2 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for the first nine months of 2025 was 580.3 actual MW, an increase of 16.7 percent from the first nine months of 2024 (497.4 actual MW). The average hourly cleared MW from RegA resources during ramp hours for the first nine months of 2025 was 440.8 actual MW, a decrease of 9.7 percent from the first

120 See Docket No. ER24-1772-000.
121 Unless otherwise noted, analysis provided in this section uses PJM market data based on PJM's internal calculations of effective MW values, based on PJM's currently incorrect MBF curve. The MMU is working with PJM to correct the MBF curve.
122 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 133 (Dec. 17, 2024).
123 Effective MW equal actual MW multiplied by the performance score and benefit factor for each unit. In the case of RegA, the benefit factor is always equal to one, and performance scores are always less than one, so effective MW of RegA are less than actual MW. For RegD resources effective MW can be larger than actual MW, if the benefit factor is greater than one. When adding RegA and RegD total MW together, actual MW can be larger or smaller than effective MW, depending on the influence of RegA MW and RegD MW.
124 PJM operations treats some nonramp hours as ramp hours, with a regulation requirement of 800 MW rather than 525 MW. All ramp/nonramp analysis performed is based on the requirement used in each hour rather than the definitions given in Table 10-37. A ramp hour occurring during what is normally a nonramp period is treated as a ramp hour.

nine months of 2024 (488.1 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for the first nine months of 2025 was 280.4 actual MW, a decrease of 1.8 percent from the first nine months of 2024 (285.5 actual MW).

Figure 10-39 Average hourly RegA actual MW offered and cleared: January through September, 2024 and 2025[125]



The average hourly offered MW from RegD resources during ramp hours for the first nine months of 2025 was 262.8 actual MW, an increase of 15.6 percent from the first nine months of 2024 (227.2 actual MW). (Figure 10-40) The average hourly offered MW from RegD resources during nonramp hours for the first nine months of 2025 was 208.4 actual MW, an increase of 5.2 percent from the first nine months of 2024 (198.1 actual MW) (Figure 10-40). The average hourly cleared MW from RegD resources during ramp hours for the first nine months of 2025 was 249.9 actual MW, an increase of 18.7 percent from the first nine months of 2024 (210.5 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for the first nine months of 2025 was 206.3 actual MW, an increase of 6.4 percent from the first nine months of 2024 (193.9 actual MW).

Figure 10-40 Average hourly RegD actual MW offered and cleared: January through September, 2024 and 2025[126]

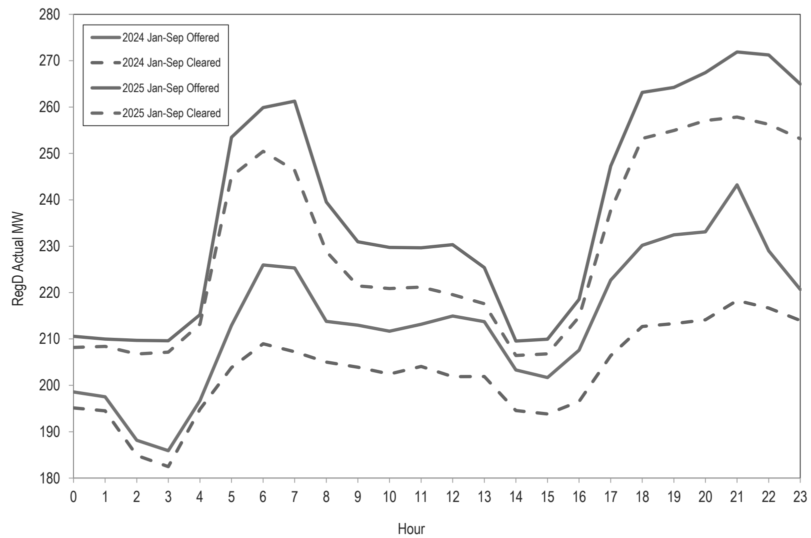


Table 10-46 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-46, the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW increased 1.8 percentage points from 3,331,636.4 MW in the first nine months of 2024 to 3,390,895.0 MW in the first nine months of 2025. The average proportion of regulation provided by battery units increased the most, by 6.1 percentage points from 27.3 percent in the first nine months of 2024 to 33.5 percent in the first nine months of 2025. Natural Gas units had the largest decrease in average proportion of regulation provided, decreasing 8.0

125 Offered MW includes MW from units that are dual offering as both RegA and RegD.

126 Offered MW includes MW from units that are dual offering as both RegA and RegD.

percentage points, from 43.2 percent in the first nine months of 2024 to 35.2 percent in the first nine months of 2025. The total regulation credits in the first nine months of 2025 were $178,968,227, an increase of 36.1 percent from $131,490,372 in the first nine months of 2024. The increase in regulation credits is due to higher energy prices in the first nine months of 2025 compared to the first nine months of 2024, resulting in a higher LOC component of the clearing price (LOC accounted for 83.2 percent of the daily weighted average clearing price), as well as higher uplift due to LOC.

When a resource offers into the regulation market, an estimated regulation LOC is added by PJM to form a total offer (units self scheduled or not providing in the energy market have a regulation LOC of zero). After a unit clears, the actual five minute interval LMP is used to calculate each unit's regulation LOC, update their total offers, and determine a marginal unit/clearing price in each five minute interval. This within hour calculation of total offers, including LOC, uses each cleared resource's rolling 100 hour average performance score. During settlements, each unit's regulation LOC and total offers are recalculated using each unit's within hour actual performance score. This recalculated LOC and offer using the actual within hour performance score is not used to recalculate the within hour clearing price. This means that the clearing price for the hour will not equal the correct clearing price. Where the resulting market price is lower than an individual resource offer adjusted for the within hour performance score, the resource is paid uplift to make up the difference.

The top 10 units that received the most regulation uplift in the first nine months of 2025 are shown in Table 10-45.

Table 10-45 Top 10 recipients of regulation uplift credits: January through September, 2025

Rank	Parent Company	Unit Name	Fuel Type	Total Regulation Uplift Credit	Share of Total Regulation Uplift Credits
1	American Electric Power Company Inc	AEP MOUNTAINEER 1 F	COAL	$3,109,318	12.6%
2	American Electric Power Company Inc	AEP MITCHELL - KAMMER 2 F	COAL	$2,249,237	9.1%
3	American Electric Power Company Inc	AEP MITCHELL - KAMMER 1 F	COAL	$2,139,957	8.6%
4	American Electric Power Company Inc	AEP AMOS 1 F	COAL	$1,869,162	7.5%
5	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$1,675,744	6.8%
6	American Electric Power Company Inc	AEP MITCHELL - KAMMER 2 F	COAL	$1,600,309	6.5%
7	American Electric Power Company Inc	AEP BIG SANDY 1 F	NATURAL GAS	$1,560,572	6.3%
8	Constellation Energy Generation LLC	PE MUDDY RUN 1-8 H	HYDRO	$1,326,908	5.4%
9	American Electric Power Company Inc	AEP AMOS 3 F	COAL	$1,146,151	4.6%
10	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$1,116,107	4.5%
Total of Top 10				$17,793,466	71.9%
Total Regulation Uplift Credits				$24,760,125	100.0%

The uplift credits received for each unit type are shown in Table 10-46. The total uplift credits received increased 14.0 percent from $21,719,251 in the first nine months of 2024 to $24,760,125 in the first nine months of 2025. This increase, like the increase in total credits, is due in part to higher LOC components of regulation prices and offers as a result of higher energy prices in the first nine months of 2025 compared to the first nine months of 2024. Natural Gas units had the largest increase in uplift payments, increasing from $6,549,837 (30.2 percent of total uplift) in the first nine months of 2024, to $10,907,339 (44.1 percent of total uplift) in the first nine months of 2025.

Table 10-46 PJM regulation by source: January through September, 2024 and 2025[127]

Year (Jan-Sep)	Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2024	Battery	22	911,076	27.3%	$31,382,451	$304	$31,382,755
	Coal	19	174,473	5.2%	$6,844,392	$13,080,694	$19,925,085
	Hydro	25	614,237	18.4%	$22,551,361	$2,088,417	$24,639,778
	Natural Gas	141	1,439,637	43.2%	$42,695,360	$6,549,837	$49,245,197
	DR	19	192,213	5.8%	$6,297,557	$0	$6,297,557
Total		226	3,331,636.4	100.0%	$109,771,121	$21,719,251	$131,490,372
2025	Battery	24	1,135,815	33.5%	$53,885,712	$151	$53,885,863
	Coal	19	174,651	5.2%	$7,252,501	$10,099,825	$17,352,326
	Hydro	27	694,011	20.5%	$32,678,952	$3,752,810	$36,431,762
	Natural Gas	142	1,193,143	35.2%	$51,245,236	$10,907,339	$62,152,575
	DR	17	193,274	5.7%	$9,145,699	$0	$9,145,699
Total		229	3,390,895.0	100.0%	$154,208,101	$24,760,125	$178,968,227

Battery Projects in the Queue

Significant flaws in the regulation market design have led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have contributed to the significant rise in storage projects entering PJM's interconnection queue from 2019 to 2023, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-47).

Table 10-47 Active battery storage projects by submitted year: January 2014 through September 2025

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	1	20.0
2016	0	0.0
2017	0	0.0
2018	6	432.0
2019	31	2,057.3
2020	39	3,476.0
2021	103	7,444.9
2022	0	0.0
2023	0	0.0
2024	0	0.0
2025 (Jan-Sep)	4	1,675.0
Total	185	15,115.2

127 Biomass data have been added to the natural gas category based on confidentiality rules.

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the first nine months of 2025 retire, the supply of regulation in PJM will be reduced by less than one percent.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 14, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours until January 9, 2017. A change to the regulation requirement was approved by the RMISTF in 2016, with an implementation date of January 9, 2017. The regulation requirement was increased from 700 effective MW to 800 effective MW during ramp hours (Table 10-37).

Table 10-48 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month. Changes in the actual MW required to satisfy the regulation requirement are the result of the amount of RegD actual MW cleared. When more RegD MW are cleared, the MBF is lower, resulting in those actual MW being worth less effective MW, requiring more actual MW to satisfy the requirement. When MBFs are higher, the actual MW of RegD are worth more effective MW, reducing the amount of actual MW needed to satisfy the requirement.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 486.9 hourly average performance adjusted actual MW in the first nine months of 2025. This is an increase of 8.3 performance adjusted actual MW from the first nine months of 2024, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 478.5 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 690.8 hourly average performance adjusted actual MW in the first nine months of 2025. This is a decrease of 6.6 performance adjusted actual MW from the first nine months of 2024, where the average hourly regulation cleared MW for ramp hours were 697.5 performance adjusted actual MW.[128]

Table 10-48 Required regulation and ratio of supply to requirement January 2024 through September 2025

		Average Required Regulation (MW)		Average Required Regulation (Effective MW)		Ratio of Supply MW to MW Requirement		Ratio of Supply Effective MW to Effective MW Requirement	
Hours	Month	2024	2025	2024	2025	2024	2025	2024	2025
Ramp	Jan	705.7	695.2	800.1	800.0	1.39	1.49	1.29	1.36
	Feb	691.8	689.8	800.0	800.0	1.36	1.44	1.27	1.33
	Mar	688.5	695.7	800.0	800.0	1.36	1.59	1.27	1.44
	Apr	691.9	686.0	800.0	800.1	1.37	1.46	1.26	1.34
	May	693.1	695.8	800.0	799.9	1.41	1.54	1.30	1.40
	Jun	703.9	694.8	799.8	800.0	1.42	1.59	1.31	1.44
	Jul	701.6	685.4	799.7	800.0	1.45	1.57	1.33	1.42
	Aug	703.2	686.8	800.0	800.0	1.48	1.58	1.35	1.43
	Sep	697.6	688.1	800.0	800.1	1.54	1.55	1.39	1.40
	Oct	693.1	-	800.1	-	1.54	-	1.39	-
	Nov	691.1	-	800.0	-	1.54	-	1.39	-
	Dec	690.7	-	800.0	-	1.50	-	1.37	-
Nonramp	Jan	477.4	488.6	525.1	525.0	1.43	1.49	1.33	1.39
	Feb	473.0	487.3	525.1	525.3	1.41	1.56	1.31	1.45
	Mar	484.8	489.7	525.1	525.0	1.54	1.69	1.42	1.55
	Apr	489.1	480.5	536.8	525.1	1.41	1.55	1.32	1.44
	May	481.8	487.1	525.0	525.0	1.49	1.57	1.37	1.45
	Jun	474.1	498.0	525.4	542.7	1.40	1.68	1.30	1.54
	Jul	479.0	482.5	527.3	525.1	1.44	1.64	1.34	1.50
	Aug	473.9	481.6	525.1	525.1	1.40	1.65	1.30	1.52
	Sep	473.7	486.5	525.5	525.1	1.47	1.74	1.35	1.59
	Oct	461.7	-	525.2	-	1.69	-	1.51	-
	Nov	479.6	-	525.0	-	1.71	-	1.55	-
	Dec	482.4	-	525.0	-	1.62	-	1.48	-

128 The supply of performance adjusted MW is less than the demand because the regulation requirement is based on effective MW. Effective MW are performance adjusted MW multiplied by the MBF.

Market Concentration

In the first nine months of 2025, the effective MW weighted average HHI of RegA resources was 2632 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 2015 which is also highly concentrated.

Table 10-49 includes a monthly summary of three pivotal supplier (TPS) results. In the first nine months of 2025, the three pivotal supplier test was failed in 94.2 percent of hours. The MMU concludes that the PJM Regulation Market in the first nine months of 2025 was characterized by structural market power. The results presented here are calculated by PJM. The MMU has been unable to verify these results, as some of the underlying data necessary to replicate these calculations are not saved. PJM submitted a request to the vendor more than five years ago to save all data necessary for verification.

Table 10-49 Regulation market monthly three pivotal supplier results: January 2024 through September 2025

	Percent of Hours Pivotal	
Month	2024	2025
Jan	96.2%	95.0%
Feb	98.1%	96.6%
Mar	94.4%	91.9%
Apr	98.8%	98.9%
May	93.3%	96.0%
Jun	96.2%	93.8%
Jul	97.3%	94.5%
Aug	94.6%	92.2%
Sep	90.0%	88.8%
Oct	91.9%	
Nov	92.5%	
Dec	93.5%	
Average	94.7%	94.2%

Market Conduct

Offers

Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[129] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100 per MW) by 1415 the day before the operating day. Regulation resources are also permitted to change and/or submit intraday offers.[130]

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00 per MW margin. The $12.00 margin embeds market power in the regulation offers, is not part of the cost of regulation, and should be eliminated. The performance component for cost-based offers is not to exceed the increased costs (increased short run marginal costs including increased fuel costs) resulting from moving the unit up and down to provide regulation. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. There is an energy storage loss component for batteries and flywheels as a cost component of regulation performance offers to reflect the net energy consumed to provide regulation service.[131]

Up until 65 minutes before the operating hour, the regulating resource must provide: status (available, unavailable, or self scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW); and the regulation signal type (RegA or RegD). Resources may offer regulation for both the RegA and RegD signals, but will be assigned to follow

129 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 132 (Sept. 1, 2024).
130 Id. at 3.2.2, at p 62.
131 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 45 (Sept. 1, 2024).

only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they are willing to provide.[132]

All LSEs are required to provide regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-52).[133] Figure 10-41 compares average hourly regulation and self scheduled regulation during ramp and nonramp hours on an effective MW basis. Self scheduled regulation averaged 52.2 percent of all effective MW during ramp hours (53.3 percent in the first nine months of 2024) and 59.2 percent of all effective MW during nonramp hours (69.3 percent in the first nine months of 2024) in the first nine months of 2025. Over all hours in the first nine months of 2025, self scheduled regulation averaged 55.0 percent of all effective MW (59.6 percent in the first nine months of 2024) (See Table 10-50). The average hourly regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.[134]

132 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 133 (Dec. 17, 2024).
133 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 98 (Dec. 17, 2024).
134 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 133 (Dec. 17, 2024).

Figure 10-41 Nonramp and ramp regulation levels: January 2024 through September 2025

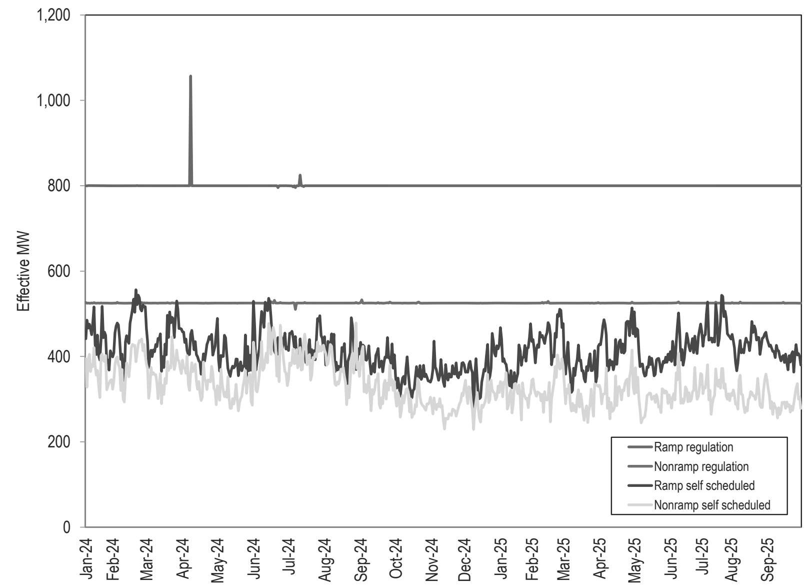


Table 10-50 Total Effective MW and Self Scheduled Effective MW during ramp and non ramp hours: January 2024 through September 2025

Year (Jan-Sep)		Effective MW	Self Scheduled Effective MW	Percent Effective MW
2024	Ramp	213,067.1	113,588.9	53.3%
	Non Ramp	139,681.2	96,799.8	69.3%
Total		352,748.4	210,388.7	59.6%
2025	Ramp	207,203.3	108,229.0	52.2%
	Non Ramp	136,001.9	80,496.8	59.2%
Total		343,205.1	188,725.8	55.0%

Table 10-51 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 52.6 percent of the total effective MW in September 2025), and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in October 2012 and 71.2 percent of all self scheduled effective MW in September 2025). In the first nine months of 2025, the average RegD percentage of total self scheduled effective MW was 68.7 percent, an increase of 5.7 percentage points from the first nine months of 2024, when the average was 63.0 percent.

Table 10-51 RegD self scheduled regulation by month: January 2024 through September 2025

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	RegD Percent of Total Self Scheduled Effective MW	RegD Percent of Total Effective MW
2024	Jan	247.3	348.5	404.2	708.4	61.2%	49.2%
2024	Feb	247.2	333.6	431.4	674.0	57.3%	49.5%
2024	Mar	251.6	332.6	395.0	639.8	63.7%	52.0%
2024	Apr	246.3	328.7	378.4	646.1	65.1%	50.9%
2024	May	244.2	326.1	347.9	639.6	70.2%	51.0%
2024	Jun	269.3	343.2	432.9	716.4	62.2%	47.9%
2024	Jul	257.8	350.8	415.0	711.5	62.1%	49.3%
2024	Aug	244.2	341.8	391.7	706.5	62.3%	48.4%
2024	Sep	227.2	318.7	359.3	639.7	63.2%	49.8%
2024	Oct	239.5	313.9	315.8	639.7	75.8%	49.1%
2024	Nov	247.9	332.3	315.4	651.0	78.6%	51.0%
2024	Dec	230.7	344.9	339.5	673.9	68.0%	51.2%
Average		246.1	334.6	377.2	619.0	65.8%	49.9%
2025	Jan	241.2	359.0	356.5	692.8	67.6%	51.8%
2025	Feb	248.1	360.8	394.8	681.5	62.8%	52.9%
2025	Mar	228.9	341.4	331.6	639.8	69.0%	53.4%
2025	Apr	233.6	339.0	365.6	639.7	63.9%	53.0%
2025	May	245.5	340.8	338.9	639.5	72.5%	53.3%
2025	Jun	281.3	373.3	390.7	712.8	72.0%	52.4%
2025	Jul	287.2	370.8	419.2	719.9	68.5%	51.5%
2025	Aug	272.1	364.3	385.2	696.8	70.6%	52.3%
2025	Sep	241.0	336.5	338.3	639.6	71.2%	52.6%
Average		253.2	354.0	369.0	673.6	68.7%	52.6%

LSE's can satisfy their obligation to provide regulation by purchasing in the spot market, self scheduling, or through bilateral agreements. Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. For total spot market regulation and self scheduled regulation, Table 10-52 shows monthly data for January 2024 through September 2025, and Table 10-53 shows annual data for January through September, 2012 through 2025. Table 10-52 and Table 10-53 are based on settled (purchased) MW.

Table 10-52 Regulation sources: spot market and self scheduled purchases: January 2024 through September 2025

Year	Month	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2024	Jan	154,709.3	206,512.1
	Feb	102,320.8	210,400.6
	Mar	119,518.6	205,632.7
	Apr	129,745.9	187,429.4
	May	162,153.9	166,226.4
	Jun	140,119.8	204,187.0
	Jul	141,454.2	211,045.4
	Aug	154,173.9	193,923.2
	Sep	128,113.1	174,698.6
	Oct	178,601.8	145,997.5
	Nov	189,442.1	143,507.1
	Dec	171,235.2	172,522.1
Total		1,771,588.7	2,222,082.2
2025	Jan	171,218.0	186,914.3
	Feb	117,470.5	192,653.8
	Mar	148,751.2	181,648.4
	Apr	110,137.4	205,198.6
	May	140,279.2	191,443.7
	Jun	147,869.9	199,499.2
	Jul	138,930.3	221,418.2
	Aug	142,901.6	207,301.3
	Sep	131,558.3	185,034.0
Total		1,249,116.4	1,771,111.6

Table 10-53 Regulation sources: spot market and self scheduled: January through September, 2012 through 2025

Year (Jan-Sep)	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2012	5,110,747.9	1,122,671.9
2013	2,528,830.3	1,478,608.5
2014	1,836,488.7	1,543,266.0
2015	1,897,225.7	1,380,004.7
2016	1,672,795.5	1,598,231.6
2017	1,849,333.5	1,372,996.2
2018	2,124,551.1	1,135,540.8
2019	1,755,035.6	1,405,707.9
2020	1,608,960.6	1,667,128.2
2021	1,766,633.1	1,555,694.7
2022	1,870,452.6	1,201,997.0
2023	1,421,896.6	1,625,251.4
2024	1,232,309.5	1,760,055.5
2025	1,249,116.4	1,771,111.6

In the first nine months of 2025, DR provided an average of 54.9 MW of regulation per hour during ramp hours (53.4 MW of regulation per hour during ramp hours in the first nine months of 2024), and an average of 36.0 MW of regulation per hour during nonramp hours (42.4 MW of regulation per hour during nonramp hours in the first nine months of 2024). Generating units supplied an average of 635.8 MW of regulation per hour during ramp hours in the first nine months of 2025 (645.3 MW of regulation per hour during ramp hours in the first nine months of 2024), and an average of 450.7 MW per hour during nonramp hours in the first nine months of 2025 (437.0 MW of regulation per hour during nonramp hours in the first nine months of 2024).

Market Performance

Price

Table 10-54 shows the regulation price and regulation cost per MW for January through September, 2009 through 2025. The weighted average RMCP for the first nine months of 2025 was $42.42 per MW. This is an increase of $11.12 per MW, or 35.5 percent, from the weighted average RMCP of $31.30 per MW in the first nine months of 2024. This increase in the regulation clearing price was the result of an increase in energy prices in the first nine months of 2025 and the related increase in the opportunity cost component of RMCP.

Table 10-54 Comparison of average price and cost for regulation: January through September, 2009 through 2025

Year (Jan-Sep)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent of Cost
2009	$24.94	$32.28	77.3%
2010	$19.47	$34.54	56.4%
2011	$17.04	$32.70	52.1%
2012	$15.16	$21.07	71.9%
2013	$33.29	$38.49	86.5%
2014	$50.19	$60.94	82.4%
2015	$35.56	$43.00	82.7%
2016	$16.52	$18.99	87.0%
2017	$15.70	$21.70	72.4%
2018	$28.21	$35.06	80.5%
2019	$14.97	$19.15	78.1%
2020	$12.59	$15.59	80.8%
2021	$20.91	$25.37	82.4%
2022	$51.04	$63.46	80.4%
2023	$22.04	$29.03	75.9%
2024	$31.30	$39.72	78.8%
2025	$42.42	$52.35	81.0%

The introduction of fast start pricing in the PJM energy market on September 1, 2021, had an effect on the regulation market LOC included in regulation offers and in the resulting clearing price for regulation. Table 10-55 shows the effect of fast start pricing on the regulation market monthly capability component of price and the total regulation market clearing price from September 2021 through September 2025. In the first nine months of 2025, fast start pricing increased the average regulation market clearing price by $3.48 (an increase of 9.0 percent), from $38.92 to $42.41, compared to dispatch pricing. This resulted in an additional $11.8 million in regulation credits.

Table 10-55 Comparison of fast start and dispatch pricing: September 2021 through September 2025[135]

Year	Month	Capability Clearing Price Dispatch	Capability Clearing Price Fast Start	Regulation Market Clearing Price Dispatch	Regulation Market Clearing Price Fast Start	Percent Fast Start Increase
2021	Sep	$27.22	$29.08	$28.55	$30.41	6.5%
	Oct	$35.64	$39.92	$37.12	$41.40	11.5%
	Nov	$50.56	$54.40	$52.43	$56.28	7.3%
	Dec	$25.62	$27.37	$27.05	$28.79	6.4%
2022	Jan	$68.25	$71.14	$69.68	$72.56	4.1%
	Feb	$31.14	$31.93	$32.76	$33.55	2.4%
	Mar	$23.91	$25.94	$25.70	$27.73	7.9%
	Apr	$45.07	$48.85	$47.49	$51.27	7.9%
	May	$38.09	$41.85	$39.84	$43.60	9.4%
	Jun	$47.26	$52.57	$49.17	$54.48	10.8%
	Jul	$47.40	$54.51	$48.92	$56.04	14.5%
	Aug	$57.43	$64.13	$59.17	$65.87	11.3%
	Sep	$46.17	$48.84	$48.07	$50.73	5.5%
	Oct	$33.38	$36.76	$35.33	$38.70	9.6%
	Nov	$21.29	$23.08	$22.42	$24.21	8.0%
	Dec	$115.65	$112.52	$116.94	$113.81	(2.7%)
Total		$48.66	$51.82	$50.37	$53.53	6.3%
2023	Jan	$16.61	$17.25	$17.58	$18.22	3.7%
	Feb	$15.12	$15.48	$16.29	$16.65	2.2%
	Mar	$17.11	$17.80	$17.89	$18.57	3.8%
	Apr	$21.51	$23.20	$22.60	$24.29	7.5%
	May	$22.75	$24.58	$24.31	$26.14	7.5%
	Jun	$19.77	$20.88	$21.27	$22.38	5.2%
	Jul	$21.45	$23.43	$22.56	$24.54	8.8%
	Aug	$20.10	$21.32	$21.17	$22.39	5.8%
	Sep	$22.34	$23.92	$23.49	$25.08	6.7%
	Oct	$28.11	$32.37	$29.25	$33.51	14.6%
	Nov	$18.48	$20.83	$18.95	$21.30	12.4%
	Dec	$16.78	$18.12	$17.81	$19.15	7.5%
Total		$20.01	$21.60	$21.10	$22.69	7.5%
2024	Jan	$35.33	$36.70	$36.91	$38.28	3.7%
	Feb	$17.72	$19.44	$18.70	$20.42	9.2%
	Mar	$20.05	$22.88	$21.21	$24.04	13.3%
	Apr	$20.36	$24.52	$20.75	$24.90	20.0%
	May	$32.60	$37.59	$33.66	$38.64	14.8%
	Jun	$27.57	$28.96	$28.29	$29.68	4.9%
	Jul	$37.03	$39.87	$38.51	$41.35	7.4%
	Aug	$29.85	$31.48	$30.56	$32.18	5.3%
	Sep	$25.66	$28.31	$27.36	$30.01	9.7%
	Oct	$33.33	$35.59	$34.27	$36.53	6.6%
	Nov	$25.68	$28.52	$26.60	$29.45	10.7%
	Dec	$31.90	$33.14	$33.45	$34.69	3.7%
Total		$28.29	$30.76	$29.39	$31.86	8.4%
2025	Jan	$57.21	$59.04	$60.17	$61.99	3.0%
	Feb	$34.73	$36.62	$36.51	$38.41	5.2%
	Mar	$31.37	$35.60	$33.70	$37.93	12.6%
	Apr	$26.33	$31.51	$26.84	$32.02	19.3%
	May	$26.44	$28.74	$27.61	$29.91	8.4%
	Jun	$56.45	$61.08	$57.81	$62.43	8.0%
	Jul	$37.82	$43.07	$39.31	$44.56	13.3%
	Aug	$26.10	$29.39	$27.48	$30.77	12.0%
	Sep	$36.70	$39.27	$38.49	$41.06	6.7%
Total		$37.28	$40.76	$38.92	$42.41	9.0%

Weighted Average Price ($/Perf. Adj. Actual MW)

135 The performance component of the regulation market clearing price is unaffected by fast start pricing.

Figure 10-42 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC). Then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). The capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-42 illustrates the components of the regulation market clearing price. Each section represents the contribution of the lost opportunity cost (green area), capability price (blue area), and performance price (orange area), to the total price. From this figure, it is clear that the lost opportunity cost is the largest component of the total clearing price. In the first nine months of 2025, LOC accounted for 86.6 percent of the daily weighted average capability price, and 83.2 percent of the daily weighted average total clearing price.

Figure 10-42 Regulation market clearing price components (Dollars per MW): January through September, 2025

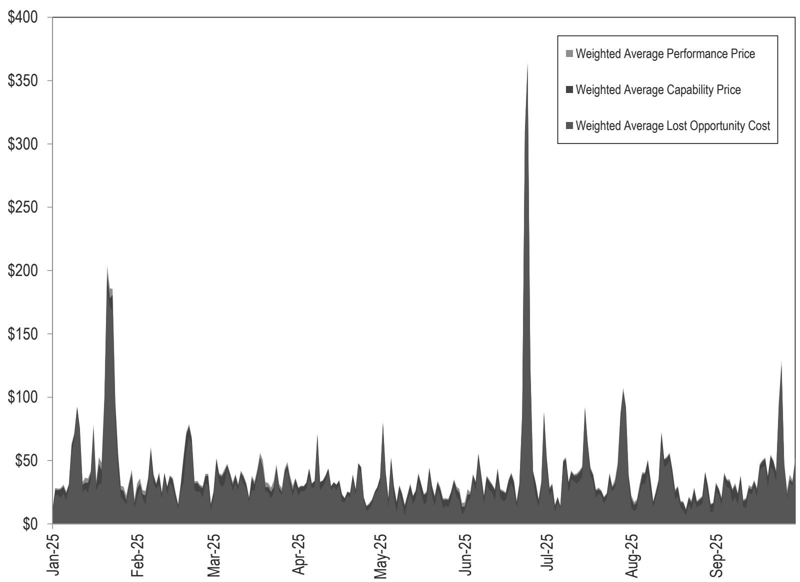


Table 10-56 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-42 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-56 Regulation market monthly component of price (Dollars per MW): January through September, 2025

Year	Month	Weighted Average Regulation Market Capability Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Performance Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Clearing Price ($/Perf. Adj. Actual MW)
2025	Jan	$59.04	$2.95	$61.99
	Feb	$36.62	$1.79	$38.41
	Mar	$35.60	$2.33	$37.93
	Apr	$31.51	$0.51	$32.02
	May	$28.74	$1.17	$29.91
	Jun	$61.08	$1.35	$62.43
	Jul	$43.07	$1.49	$44.56
	Aug	$29.39	$1.38	$30.77
	Sep	$39.27	$1.80	$41.06
Average		$40.76	$1.65	$42.41

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown Table 10-57. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in the first nine months of 2025 was $182,648,615, compared to $136,117,391 in the first nine months of 2024.

Table 10-57 Total regulation charges: January 2024 through September 2025

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2024	Jan	408,753.4	$20,438,488	$38.28	$50.00	76.6%
	Feb	359,472.4	$9,511,886	$20.42	$26.46	77.2%
	Mar	373,821.3	$11,459,995	$24.04	$30.66	78.4%
	Apr	365,623.4	$11,540,004	$24.90	$31.56	78.9%
	May	370,688.3	$17,378,965	$38.64	$46.88	82.4%
	Jun	394,543.8	$14,952,926	$29.68	$37.90	78.3%
	Jul	409,957.7	$21,711,218	$41.35	$52.96	78.1%
	Aug	404,773.1	$16,107,937	$32.18	$39.79	80.9%
	Sep	354,056.7	$13,015,973	$30.01	$36.76	81.6%
	Oct	367,726.3	$16,434,456	$36.53	$44.69	81.7%
	Nov	368,499.2	$13,925,495	$29.45	$37.79	77.9%
	Dec	392,668.3	$16,734,410	$34.69	$42.62	81.4%
Total		4,570,583.9	$183,211,752	$31.86	$40.08	79.5%
2025	Jan	405,434.3	$31,451,421	$61.99	$77.57	79.9%
	Feb	357,640.4	$16,335,357	$38.41	$45.68	84.1%
	Mar	376,469.6	$19,303,608	$37.93	$51.28	74.0%
	Apr	367,193.0	$15,142,726	$32.02	$41.24	77.6%
	May	383,116.9	$14,388,435	$29.91	$37.56	79.6%
	Jun	404,541.1	$29,706,971	$62.43	$73.43	85.0%
	Jul	420,570.5	$22,269,279	$44.56	$52.95	84.1%
	Aug	406,661.9	$15,348,773	$30.77	$37.74	81.5%
	Sep	367,465.3	$18,702,046	$41.13	$50.89	80.8%
Total		3,489,092.9	$182,648,615	$42.42	$52.35	81.0%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-58. Total scheduled regulation is based on settled performance adjusted MW. In the first nine months of 2025, the average total cost of regulation was $52.35 per MW, 33.2 percent higher than $39.31 in the first nine months of 2024. In the first nine months of 2025, the monthly average capability component cost of regulation was $40.75, 34.8 percent higher than $30.24 in the first nine months of 2024. In the first nine months of 2025, the monthly average performance component cost of regulation was $4.49, 62.7 percent higher than $2.76 in the first nine months of 2024. The increase of the average total cost in the first nine months of 2025 versus the first nine months of 2024, was primarily a result of higher LOC values due to higher prices in the energy market.

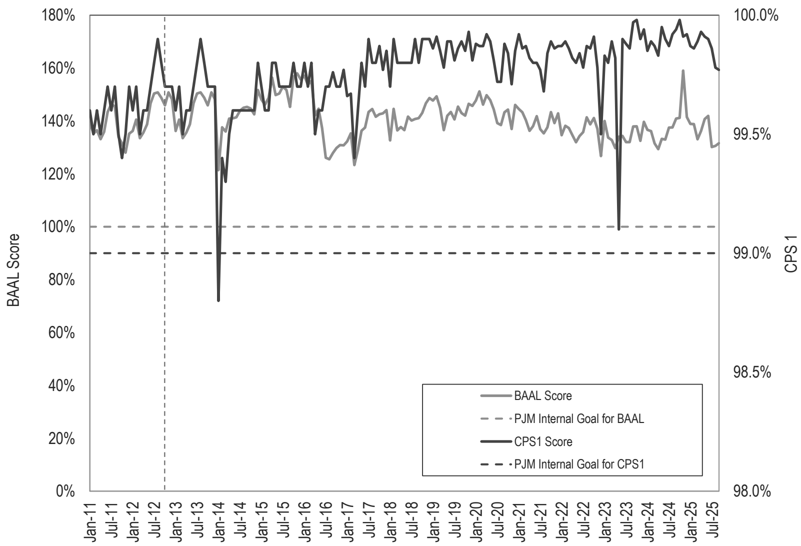
Table 10-58 Components of regulation cost: January 2024 through September 2025

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2024	Jan	408,753.4	$36.74	$3.97	$7.81	$48.52
	Feb	359,472.4	$19.47	$2.40	$4.02	$25.89
	Mar	373,821.3	$22.90	$2.93	$4.84	$30.66
	Apr	365,623.4	$24.56	$0.97	$6.03	$31.56
	May	370,688.3	$37.61	$2.58	$6.70	$46.88
	Jun	394,543.8	$28.96	$1.72	$7.21	$37.90
	Jul	409,957.7	$39.90	$3.90	$9.16	$52.96
	Aug	404,773.1	$31.53	$1.76	$6.51	$39.79
	Sep	354,056.7	$28.31	$4.58	$3.87	$36.76
	Oct	367,726.3	$35.58	$2.48	$6.67	$44.72
	Nov	368,499.2	$28.53	$2.47	$6.81	$37.81
	Dec	392,668.3	$33.14	$4.00	$5.50	$42.64
Total		4,570,583.9	$30.78	$2.82	$6.49	$40.08
2025	Jan	405,434.3	$59.07	$7.58	$10.92	$77.57
	Feb	357,640.4	$36.54	$4.79	$4.34	$45.68
	Mar	376,469.6	$35.56	$6.42	$9.30	$51.28
	Apr	367,193.0	$31.42	$1.40	$8.41	$41.24
	May	383,116.9	$28.71	$3.40	$5.44	$37.56
	Jun	404,541.1	$61.12	$3.76	$8.56	$73.43
	Jul	420,570.5	$43.12	$4.01	$5.82	$52.95
	Aug	406,661.9	$29.40	$3.92	$4.42	$37.74
	Sep	367,465.3	$39.19	$5.03	$6.67	$50.89
Total		3,489,092.9	$40.75	$4.49	$7.11	$52.35

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-43 for every month from January 2011 through September 2025 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[136] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-43 Monthly CPS1 and BAAL performance: January 2011 through September 2025



136 See *2019 Annual State of the Market Report for PJM*, Appendix F: Ancillary Services.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[137]

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of cost of service rates defined in the tariff.[138] Currently, there are a small number of units in unique circumstances with bilateral agreements with their transmission operator (TO) to provide black start service that were entered into prior to joining PJM. These units are compensated directly by the TO.

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service is a regional approach that recognizes cost effective ways to provide black start across transmission zonal boundaries.[139] PJM does not adequately use a regional or cross zonal approach to providing black start. Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.[140] But PJM's stated principles for system restoration are not fully incorporated into the rules in Schedule 6A. Costs should also be allocated on a regional basis to reflect the regional benefits of black start service.

The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely zonal basis. Similarly, the region as a whole benefits from black start service, regardless of the transmission zone in which it is located, and the costs of black start service should be shared equally across the region.

137 OATT Schedule 1 § 1.3BB.
138 See OATT Schedule 6A para. 18.
139 See Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C to Comments, FERC Docket No. ER13-1911-000 (August 19, 2013) at 5 ("To be sure, restoration plans utilizing interconnecting Transmission Owners is not new and is currently included in all restoration plans today. Geographic or political boundaries play no role in the evaluation of the most reliable and efficient restoration strategies.").
140 See Docket No. ER13-1911-000.

Fuel Assurance

By order issued October 6, 2023, the FERC approved revisions to Schedule 6A concerning fuel assurance for black start units, effective July 12, 2023.[141] The revisions were approved over the protest of the MMU, which identified significant flaws.[142] The planning criteria for fuel assured units and charges are applied on a zonal basis and not a regional basis, even though PJM is a regional transmission operator. The revisions to the tariff ignore the attributes of existing fuel assured units if they do not offer into the fuel assurance RFP. Intermittent resources are treated as if they are fuel assured. The X factor for fuel assured hydro units is arbitrarily doubled from 0.01 to 0.02. The incentive factor for fuel assured units is arbitrarily doubled from 10 percent to 20 percent. For black start units in service prior to June 6, 2021, the rules apply CRF rates that ignore significant reductions in federal tax rates, including depreciation provisions, resulting in significant overpayments by PJM customers. The rules do not address environmental permits, which may limit the ability of units to provide black start service. The rules do not define DER's provision of black start service. The rules do not require testing units without notice to operators. The rules do not address the availability of natural gas and stored water levels. Reporting requirements for onsite fuel are not adequate. The reliability backstop improperly depends on TOs to secure black start service if PJM has two failed auctions.

The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones.

Definition of Black Start Costs

In the November 8, 2024, MIC meeting PJM proposed to change the definition of Net CONE used in the Black Start Base Formula Rate (BFR) calculation.[143] The Base Formula Rate is a formula based cost of service rate and not a market based rate. The rationale was that Net CONE values based on a combined cycle reference resource defined for the capacity market could be negative at times. PJM did not retract its proposal even after PJM decided to use a combustion turbine as the reference resource rather than a combined cycle as the reference resource. That change eliminated PJM's identified issue with negative Net CONE values. The MMU presented historical information on payments under the BFR rate and argued that no change is needed to the Net CONE calculation.[144] PJM filed its proposal with the Commission on April 30, 2025.[145] The MMU filed a protest, and, after a deficiency letter issued and PJM responded, filed additional comments.[146]

Ultimately PJM's argument is simply that the current tariff calculation would result in a short term decrease in black start payments under the Base Formula Rate which includes Net CONE, and PJM did not want the rate to decrease. PJM proposed to use average Net CONE for the entire RTO over the last five years as a fixed value subject to escalation. PJM's approach means that both Gross CONE and the net revenue offset will be escalated using an inflation index. It is illogical to escalate net revenue because net revenue is a function of the dynamics of the energy market and the fuel markets. Given the current and expected high levels of Gross CONE compared to the five year average, PJM's proposal could actually reduce payments to these black start resources compared to the status quo. PJM did not address that possibility. PJM failed to explain why their proposal is a reasonable approach to compensating these resources for providing black start service. PJM provided no information about the actual costs of providing black start service. PJM provided no information about the actual mark up over costs currently paid to these black start resources. PJM's proposal does not approximate black start service costs and fails to even attempt to demonstrate any relationship to black start service costs. Under an approach that uses Net CONE, PJM does not justify using system wide Net CONE rather than locational Net CONE.

The MMU's position is that if the black start rate under the Base Formula Rate is to be reevaluated, it should be based on the actual cost of providing the black start service, plus an incentive, rather than the unsupported use of Net CONE, escalated each year.

141 See 85 FERC ¶ 91,000.

142 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER23-1874-000 (June 6, 2023) and Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, FERC Docket No. ER23-1874-000 (July 6, 2023).

143 See MIC, Problem Statement and Issues Charge, "Black Start Base Formula Rate," <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241108/20241108-item-03-1---black-start-base-formula-rate---problem-statement.pdf> and <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241108/20241108-item-03-2---black-start-base-formula-rate---issue-charge.pdf> (Nov. 8, 2024).

144 See MIC, IMM Education, Black Start Costs and Net CONE <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250205/20250205-item-03-2---black-start-base-formula-rate---imm-solution.pdf> (February 5, 2025).

145 See PJM Filing, Docket No. ER25-2123-000.

146 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER25-2123-000 (May 21, 2025); Comments of the Independent Market Monitor for PJM, FERC Docket No. ER25-2123-000 (July 21, 2025).

Black Start Backstop Process

PJM Manual 14D defines a Black Start Reliability Backstop Process that is implemented in the event that PJM does not acquire enough black start resources through the RFP process. One option under this process is that one or more Transmission Owners can take responsibility for procuring the needed black start resources in their zones.

The triggers that initiate the backstop process are: a black start generation shortage or a failure to meet the fuel assurance criteria in a zone; and two failed RFPs; and no cross-zonal solutions available; and no RTEP transmission solutions available.[147] The steps in the reliability backstop process are defined in Manual 14D.[148]

The backstop process for black start service is flawed. PJM has units in each zone which are fuel assured capable but are ignored if they do not bid into a fuel assured RFP. There is no reason to believe that TOs can procure black start more effectively than PJM. TOs should not own generation under cost of service regulation because it is inconsistent with competitive markets. PJM should continue its efforts until their goals are met. It is PJM's responsibility to manage black start capability.[149]

The MMU recommends that the reliability backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources.

RFPs for Black Start Service

PJM requires a minimum of one fuel assured black start site in each zone or two non fuel assured black start sites connected to different pipelines per zone.[150] New or existing black start units that wish to be designated as fuel assured black start units must offer into the PJM fuel assured RFP.[151]

In order for a unit to be considered fuel assured, it must have one of five characteristics: onsite fuel; be capable of operating independently on two or more pipelines; be directly connected to a natural gas gathering system; hydro, non-hydro and intermittent resources must be capable of 16 hours full load with 90 percent confidence. A zone meets the fuel assurance requirement if the zone includes a minimum of two gas units connected to two separate natural gas pipelines.[152]

On April 7, 2021, PJM issued an incremental RFP for black start service in the BGE and PEPCO Zones. On November 1, 2021, PJM made awards for the April 7, 2021, incremental RFP. The in service date was May 2024. On August 1, 2022, PJM issued an incremental RFP for black start service in the PECO Zone. No awards were made.

On June 20, 2023, PJM issued an RTO wide request for proposals (RFP) in accordance with the five year black start selection process. The RFP was for black start service and fuel assured black start service. PJM awarded ten existing black start units fuel assured black start service status.

On April 29, 2024, PJM issued an incremental RFP for fuel assured black start service, because the 2023 RFP did not attract offers for fuel assured black start units in all zones. There were not enough offers in the incremental fuel assured black start RFP issued April 29, 2024.

Despite the fact that April 29, 2024 auction process is not expected to be completed until January 2026, PJM has started the reliability backstop process.

The premature implementation of the reliability backstop process illustrates the inefficiency and excess cost to customers of ignoring the attributes of existing fuel assured units if they do not offer into the fuel assurance RFP. PJM has failed to consider whether existing black start resources meet the fuel assurance goals regardless of whether they applied for fuel assurance status.

147 See "PJM Manual 14D: Generator Operational Requirements," §10.3 Black Start Reliability Backstop Process, Rev. 67 (March. 19, 2025).
148 See "PJM Manual 14D: Generator Operational Requirements," §10.3 Black Start Reliability Backstop Process, Rev. 67 (March. 19, 2025).
149 See 144 FERC ¶ 61,191 (2013).
150 See "PJM Manual 36: System Restoration," §1.2 Minimum Critical Black Start Requirement, Rev. 35 (June. 15, 2025).
151 See "PJM Manual 14D: Generator Operational Requirements," §10.1 Black Start Selection Process, Rev. 67 (March. 19, 2025).
152 See "PJM Manual 12: Balancing Operations," §4.5.7 Minimum Critical Black Start Unit and Fuel Assurance Black Start Unit Requirements, Rev. 55 (June. 18, 2025).

Black Start Charges

Total black start charges are the sum of black start revenue requirement charges and black start uplift (operating reserve) charges.

Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor applicable when CRF rates are not used. The tariff specifies how to calculate each component of the revenue requirement formula.[153]

Fixed black start service costs are calculated using one of three methods chosen by the black start provider from the options defined in the OATT Schedule 6A: base formula rate; capital cost recovery rate; or incremental black start NERC-CIP cost recovery. The base formula rate is Net CONE multiplied by the black start unit's capacity multiplied by the X factor. The X factor is 0.01 for hydro units and 0.02 for CT units. The capital recovery rate is the capital investment multiplied by the CRF rate. The incremental NERC-CIP cost, for existing black start resources that need to add additional capital to meet NERC-CIP requirements, is calculated using the capital cost recovery rate. Black start uplift charges are paid to units committed in real time to provide black start service or for black start testing.[154] Total black start charges are allocated monthly to PJM customers based on their zone and nonzone peak transmission use and point to point transmission reservations.[155]

No black start units have requested new or additional black start NERC – CIP Capital Costs.[156]

In the first nine months of 2025, total black start charges were $39.6 million, a decrease of $15.6 million (28.3 percent) from the first nine months 2024. In the first nine months of 2025, total revenue requirement charges were $39.2 million, a decrease of $15.7 million (28.6 percent) from the first nine months 2024. In the first nine months of 2025, total uplift charges were $0.4 million, a increase of $0.10 million (30.4 percent) from the first nine months 2024. Table 10-59 shows total charges for January through September of each year from 2010 through 2025.[157]

Table 10-59 Black start revenue requirement charges: January through September, 2010 through 2025

Jan-Sep	Revenue Requirement Charges	Uplift Charges	Total
2010	$8,527,000	$0	$8,527,000
2011	$9,996,898	$0	$9,996,898
2012	$13,288,491	$0	$13,288,491
2013	$15,728,447	$68,903,357	$84,631,804
2014	$18,395,320	$26,661,658	$45,056,978
2015	$39,718,855	$5,070,944	$44,789,799
2016	$51,565,656	$180,265	$51,745,921
2017	$52,422,434	$186,752	$52,609,186
2018	$48,938,203	$152,720	$49,090,923
2019	$48,231,346	$175,400	$48,406,746
2020	$49,052,199	$163,301	$49,215,499
2021	$50,278,321	$203,620	$50,481,941
2022	$51,357,993	$352,984	$51,710,976
2023	$49,897,290	$261,396	$50,158,686
2024	$54,904,846	$313,896	$55,218,742
2025	$39,208,630	$409,395	$39,618,025

153 *See* OATT Schedule 6A para. 18.
154 There are no black start units currently using the ALR option.
155 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
156 OATT Schedule 6A para. 21. "The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit."
157 Starting December 1, 2012, PJM defined a separate black start uplift category. ALR units accounted for the high uplift charges in 2013 – 2015. All ALR units had been replaced by April 2015.

Black start zonal charges in 2025 ranged from $0 in the OVEC and REC Zones to $6,582,256 in the AEP Zone. For each zone, Table 10-60 shows black start charges, zonal peak loads, and black start rates (calculated as charges per MW-day).[158] [159]

Table 10-60 Black start zonal charges: January through September, 2024 and 2025[160]

	Jan-Sep 2024					Jan-Sep 2025				
Zone	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)
ACEC	$1,581,474	$9,364	$1,590,838	2,638	$2.21	$1,706,944	$23,062	$1,730,007	2,566	$2.47
AEP	$13,788,860	$23,663	$13,812,523	22,909	$2.21	$6,569,375	$12,880	$6,582,256	22,318	$1.08
APS	$4,448,421	$6,602	$4,455,023	9,337	$1.75	$3,203,901	$18,366	$3,222,267	8,938	$1.32
ATSI	$3,659,291	$8,398	$3,667,688	12,007	$1.12	$2,248,934	$9,162	$2,258,097	12,508	$0.66
BGE	$2,870,425	$6,417	$2,876,842	6,429	$1.64	$2,821,420	$8,803	$2,830,223	6,766	$1.53
COMED	$6,278,773	$52,380	$6,331,152	22,549	$1.03	$3,325,623	$82,440	$3,408,062	21,560	$0.58
DAY	$177,059	$18,647	$195,707	3,253	$0.22	$166,660	$48,313	$214,973	3,365	$0.23
DUKE	$285,849	$15,060	$300,909	5,154	$0.21	$261,839	$14,139	$275,979	5,171	$0.20
DUQ	$704,867	$1,199	$706,067	2,543	$1.02	$652,615	$1,272	$653,887	2,691	$0.89
DOM	$3,513,209	$101,783	$3,614,992	22,270	$0.59	$2,429,523	$91,595	$2,521,118	23,118	$0.40
DPL	$942,018	$12,255	$954,273	4,092	$0.85	$865,122	$9,522	$874,644	4,189	$0.76
EKPC	$238,311	$13,893	$252,204	3,769	$0.25	$227,680	$20,087	$247,767	3,748	$0.24
JCPLC	$364,285	$953	$365,238	5,752	$0.23	$424,639	$2,248	$426,887	6,184	$0.25
MEC	$360,972	$7,221	$368,192	2,901	$0.46	$313,615	$10,071	$323,686	3,067	$0.39
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$1,058,996	$2,099	$1,061,096	8,193	$0.47	$1,027,788	$1,638	$1,029,426	8,652	$0.44
PE	$3,075,110	$8,340	$3,083,450	2,773	$4.07	$1,873,077	$149	$1,873,226	2,953	$2.32
PEPCO	$3,374,958	$1,839	$3,376,797	5,893	$2.10	$5,253,422	$24,997	$5,278,419	6,162	$3.14
PPL	$3,433,316	$176	$3,433,491	7,109	$1.77	$2,223,935	$324	$2,224,258	7,460	$1.09
PSEG	$1,212,231	$3,645	$1,215,876	9,596	$0.46	$861,178	$3,592	$864,770	10,152	$0.31
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$3,536,422	$19,963	$3,556,384	11,018	$1.18	$2,751,338	$26,735	$2,778,074	12,205	$0.83
Total	$54,904,846	$313,896	$55,218,742	170,186	$1.19	$39,208,630	$409,395	$39,618,025	173,770	$0.84

158 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 7.3 Black Start Service Charges, Rev. 102 (Jan. 23, 2025).
159 For each zone and import export/wheels the black start rates ($/MW day) are calculated by taking total charges by zone and divided by peak load then divided by days in the period.
160 Peak load for each zone is used to calculate the black start rate per MW day.

Table 10-61 provides a revenue requirement estimate by zone for the 2025/2026, 2026/2027, and 2027/2028 Delivery Years.[161] Revenue requirement values are rounded up to the nearest $50,000, reflecting the uncertainty about future black start revenue requirement costs. These values are illustrative only. The estimates are based on the best available data including current black start unit revenue requirements, expected black start unit termination and in service dates, changes in recovery rates, and owner provided cost estimates of incoming black start units at the time of publication and may change significantly. The estimates do not reflect the impact of FERC decisions that could affect compensation for black start.

Table 10-61 Black start zonal revenue requirement estimate: 2025/2026 through 2027/2028 Delivery Years

Zone	2025 / 2026 Revenue Requirement	2026 / 2027 Revenue Requirement	2027 / 2028 Revenue Requirement
ACEC	$2,450,000	$2,450,000	$2,300,000
AEP	$9,200,000	$7,950,000	$7,900,000
APS	$2,750,000	$1,150,000	$1,150,000
ATSI	$3,250,000	$3,150,000	$3,150,000
BGE	$4,150,000	$4,150,000	$4,150,000
COMED	$3,000,000	$2,450,000	$2,450,000
DAY	$250,000	$250,000	$250,000
DUKE	$400,000	$450,000	$450,000
DUQ	$950,000	$400,000	$400,000
DOM	$3,050,000	$2,550,000	$2,550,000
DPL	$1,050,000	$1,000,000	$1,000,000
EKPC	$350,000	$400,000	$400,000
JCPLC	$600,000	$650,000	$650,000
MEC	$550,000	$600,000	$600,000
OVEC	$0	$0	$0
PECO	$1,450,000	$1,500,000	$1,500,000
PE	$1,000,000	$1,100,000	$1,100,000
PEPCO	$7,850,000	$7,900,000	$7,900,000
PPL	$1,550,000	$1,550,000	$1,550,000
PSEG	$850,000	$900,000	$900,000
REC	$0	$0	$0
Total	$44,700,000	$40,550,000	$40,350,000

161 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

CRF Issues

The capital recovery factor (CRF) defines the revenue requirement of black start units when new equipment is added to provide black start capability.[162] The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. CRFs are calculated using a formula (or a correctly defined standard financial model) that accounts for the weighted average cost of capital and its components, plus depreciation and taxes. The PJM CRF table was created in 2007 as part of the new RPM capacity market design.[163] That CRF table provided for the accelerated return of incremental investment in capacity resources based on concerns about the fact that some old coal units would be making substantial investments related to pollution control. The CRF values were later added to the black start rules.[164] The CRF table in the tariff included assumptions about tax rates that were significantly too high after the changes to the tax code in 2017. The PJM tariff tables including CRF values should have been changed for both black start and the capacity market when the tax laws changed in 2017.

The CRF table for existing black start units includes the column header, term of black start commitment, which is misleading and incorrect. The column is simply the cost recovery period. Accelerated recovery reduces risk to black start units and should not be the basis for a shorter commitment. Full payment of all costs of black start investment on an accelerated basis should not be a reason for a shortened commitment period. Regardless of the recovery period, payment of the full costs of the black start investment should require commitment for the life of the unit.[165] In addition, there is no need for such short recovery periods for black start investment costs. Two periods, based on unit age, are more than adequate.

162 *See* OATT Schedule 6A para. 18.
163 See OATT Attachment DD § 6.8(a).
164 See OATT Schedule 6A.
165 PJM's recent filing to revise Schedule 6A includes a required commitment to provide black start service for the life of the unit. See FERC Docket No. ER21-1635.

The U.S. Internal Revenue Code changed significantly in December 2017.[166] [167] The PJM CRF table did not change to reflect these changes.[168] [169] As a result, CRF values have overcompensated black start units since the changes to the tax code. The new tax law allows for a more accelerated depreciation and reduced the corporate tax rate to 21 percent.

Updated CRF rates, incorporating the tax code changes and applicable to all black start units, should have been implemented immediately. The updated CRF rates should apply to all black start units because the actual tax payments for all black start units were reduced by the tax law changes. Without this change, black start units are receiving and will continue to receive an unexpected and inappropriate windfall.

On April 7, 2021, PJM filed with FERC to update the CRF values for new black start service units.[170] PJM proposed to bifurcate the CRF calculation, applying an updated CRF calculation that incorporates the new federal tax law to new black start units while leaving the outdated and incorrect CRF in place for existing black start units. Rather than fix the inaccurate CRF values used for existing black start units, PJM's filing would have made the use of inaccurate values permanent. The MMU filed comments on April 28, 2021.[171] The MMU objected to the continued use of the outdated CRF for existing units. The MMU also introduced a CRF formula for calculating the CRF for new black start units and requested that the CRF formula be included in the tariff.[172] [173] On August 10, 2021, FERC issued an order ("August 10th Order") that accepted PJM's tariff revisions that apply to new black start units (selected for service after June 6, 2021) and directed PJM to include the CRF formula proposed by the MMU.[174] The August 10th Order also established a show cause proceeding in a new docket to "determine whether the existing rates for generating units providing Black Start Service (Black Start Units), which are based on a federal corporate income tax that pre-dates the Tax Cuts and Jobs Act of 2017 (TCJA), remains just and reasonable."[175] The MMU requested rehearing over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[176] [177] The request for rehearing was denied.[178] PJM's compliance filing to address the August 10 Order was accepted by letter order, subject to edits proposed by the MMU, on December 16, 2021.[179]

PJM's response to the show cause directive in the August 10th Order continued to support the use of the outdated CRF despite the Commission's statement that the CRF values "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[180] [181] The MMU responded with analysis showing that PJM's proposal for maintaining the outdated CRF values would result in significant over recovery of black start capital investments.[182] In March 2023, FERC issued an order establishing hearing and settlement judge procedures.[183] Settlement talks continued and in January 2024 Commission Trial Staff moved to suspend the proceeding because a settlement had been reached in principle.[184] The MMU filed comments in opposition to the settlement, and the settlement was not certified to the Commission.[185] [186] The hearing process then resumed, but rather than hold a hearing, PJM, with the support of FERC Staff, submitted a second offer of settlement on behalf of itself and certain black start unit owners, AMP, ODEC and the PJM ICC. The settlement included exactly the same values as the first settlement, but also included affidavits. By order issued September 23, 2025, the Commission approved the second offer of settlement over the MMU's objection.[187]

166 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).
167 26 U.S. Code §11(b).
168 The corporate tax rate was lowered to 21 percent and bonus depreciation, which allows generator owners to depreciate 100 percent of the capital investment in the first year of operation, was introduced.
169 Bonus depreciation is 100 percent for capital investments placed in service after September 27, 2017 and before January 1, 2023. Bonus depreciation is 80 percent for capital investments placed in service after December 31, 2022 and before January 1, 2024, and the bonus depreciation level is reduced by 20 percent for each subsequent year through 2026. Capital investments placed in service after December 31, 2026 are not eligible for bonus depreciation. See 26 U.S. Code §168(k)(6)(A).
170 *See* Docket No. ER21-1635-000.
171 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000 (April 28, 2021).
172 See Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
173 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
174 See 176 FERC ¶ 61,080 at 42 and 44 (2021).
175 176 FERC ¶ 61,080 at 2 (2021).
176 *Id.* at 50.
177 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
178 See 177 FERC ¶ 62,017 (2021).
179 See 177 FERC ¶ 61,202 (2021).
180 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
181 August 10th Order at 47.
182 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).
183 See 182 FERC ¶ 61,194.
184 Motion of Commission Trial Staff to Suspend Procedural Schedule and Shorten Answer Period, Docket No. EL21-91-003 (January 10, 2024).
185 Comments of the Independent Market Monitor for PJM in Opposition to Offer of Settlement, Docket No. EL21-91-000, -003 (February 20, 2024).
186 186 FERC ¶ 63,019 (2024).
187 See 193 FERC ¶ 61,059.

There are 49 black start generators that have received payments based on the outdated CRF. Thirteen of the units have completed their black start capital cost recovery terms. Sixteen units started their black start service prior to January 1, 2018, and are currently receiving capital recovery payments. These units would not have been eligible for the TCJA bonus depreciation. The remaining 20 black start generators began their service terms after January 1, 2018, and are currently receiving capital recovery payments. Units with capital investments that began black start service after January 1, 2018, would have been eligible for bonus depreciation.

The November 15, 2024 settlement reduced the capital recovery payments for 38 black start generators. Table 10-62 shows the new CRF values from the settlement. The settlement CRF values became effective on January 1, 2024.

Table 10-62 Settlement CRF Values

Capital Recovery Period (years)	Original CRF Value	November 2024 Settlement CRF Value
5	0.363	0.310
10	0.198	0.177
15	0.146	0.135
20	0.125	0.118

There is no financial basis for the settlement CRF values and the settlement will result in significant over recovery for the owners of the black start generators. The settlement reduced the excess recovery payments from $89.7 million to $74.1 million.

Of the 36 units that are still receiving black start recovery payments, all but ten have fully recovered the capital investment. In other words, the owners of the units have received sufficient revenue to cover the return on and the return of the capital investments and the income tax liabilities associated with the capital recovery revenue. If recovery payments for these 26 units were stopped immediately and if the recovery payments for the ten other units were stopped in the future when the units reached full recovery, an additional $58.9 million in excess payments could be avoided.

On July 4, 2025, with the enactment of the One Big Beautiful Bill Act ("OBBBA"), the bonus depreciation rules changed again. Section 70301 of OBBBA (I.R.C. § 168(k)) allows 100 percent bonus depreciation for "qualified production property ("QPP") acquired and placed in service on or after January 20, 2025.[188] QPP means nonresidential real property used in manufacturing, production, or refining of tangible personal property in the United States.[189] To be eligible, construction must begin after January 19, 2025, and before January 1, 2029, and the property must be placed in service before January 1, 2031.[190] The formula rate calculation of the CRF values in Paragraph 18 of OATT Schedule 6A for units entering service after June 6, 2021, must be implemented to reflect the correct bonus depreciation. It is essential that PJM not repeat its earlier mistake when it ignored the tax law changes in 2017.

Reactive Service and Capability

Under Schedule 2 to the OATT, suppliers of reactive power have been compensated separately for both reactive service and reactive capability.[191] [192] [193] [194]

On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM.[195] On January 28, 2025, PJM submitted a compliance filing to implement Order No. 904 ("Compliance Filing").[196] The Compliance Filing proposed a transition mechanism lasting through May 31, 2026. On August 4, 2025, the Commission accepted PJM's termination of separate Schedule 2 payments after May 31, 2026, but rejected PJM's proposed transition mechanism and the MMU's proposed enhancements to that mechanism.[197] The current rules apply until payments under Schedule 2 terminate.

188 OBBBA § 70301(c)(1).
189 OBBBA § 70307(a)(2).
190 *Id.*
191 See MMU, 2024 State of the Market Report for PJM: January–September (November 14, 2024) at 652–656, for history and analysis of reactive power in PJM.
192 See Order No. 2003, 104 FERC ¶ 61,103 at P 544 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *CAISO*, 160 FERC \ 61,035 at P 19 (2017); *SPP*, 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20–21 (2022).
193 See OATT Attachment O.
194 See *MISO*, 182 FERC ¶ 61,033 at P 52 (January 27, 2023) (*MISO*); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546.
195 See *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 ("Order No. 904").
196 See Docket No. ER25-1073.
197 See 192 FERC ¶ 61,113; see also, Comments of the Independent Market Monitor for PJM, Docket No. ER25-1073 (February 18, 2025).

Reactive Costs

Customers in PJM paid total reactive capability charges of $273.1 million in the first nine months of 2025. Under the current rules, effective through May 31, 2026, compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT.[198] Reactive capability credits are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[199] Reactive service credits are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Compensation for reactive power service is based on real-time lost opportunity costs.[200]

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements. Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers based on their zonal and to any nonzonal (outside of PJM) peak transmission use and daily average point to point transmission reservations.[201] [202]

In the first nine months of 2025, total reactive charges were $273.7 million, a decrease of $12.1 million (4.24 percent) from the first nine months of 2024. In the first nine months of 2025, total reactive capability charges were $273.1 million, a decrease of $11.7 million (4.1 percent) from the first nine months 2024. In the first nine months of 2025, total reactive service charges were $0.59 million, a decrease of $0.416 million (41.39 percent) from the first nine months 2024. Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $42.7 million in the AEP Zone in the first nine months of 2025.

Table 10-63 shows reactive service charges for January through September of each year from 2010 through 2025.

198 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 102 (Jan. 23, 2025); 192 FERC ¶ 61,113 (2025).
199 See OATT Schedule 2.
200 See OA Schedule 1 § 3.2.3B.
201 OATT Schedule 2.
202 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 102 (Jan. 23, 2025).

Table 10-63 Reactive service charges and reactive capability charges: January through September, 2010 through 2025

Jan-Sep	Reactive Service Charges	Reactive Capability Charges	Total
2010	$8,813,427	$181,213,186	$190,026,613
2011	$20,783,028	$190,228,706	$211,011,735
2012	$49,432,233	$204,638,358	$254,070,591
2013	$184,710,913	$207,126,733	$391,837,646
2014	$27,516,739	$210,968,737	$238,485,476
2015	$9,989,075	$206,994,671	$216,983,746
2016	$838,204	$219,793,594	$220,631,798
2017	$14,047,245	$226,620,331	$240,667,577
2018	$12,428,626	$225,234,508	$237,663,134
2019	$465,836	$245,251,333	$245,717,170
2020	$412,336	$257,849,546	$258,261,882
2021	$738,644	$270,223,222	$270,961,867
2022	$1,225,976	$288,498,024	$289,723,999
2023	$500,030	$291,180,807	$291,680,837
2024	$1,005,531	$284,786,353	$285,791,884
2025	$589,322	$273,077,696	$273,667,018

Table 10-64 shows zonal reactive service charges, reactive capability charges and total charges for the first nine months of 2024 and 2025. Reactive service charges show charges to each zone for reactive service. Reactive capability charges show charges to each zone for reactive capability.

Table 10-64 Reactive service charges and reactive capability charges by zone: January through September, 2024 and 2025

	Jan-Sep 2024			Jan-Sep 2025		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$807,790	$1,901,387	$2,709,177	$0	$1,516,115	$1,516,115
AEP	$0	$45,161,311	$45,161,311	$0	$42,647,162	$42,647,162
APS	$329	$15,418,866	$15,419,195	$6,825	$14,508,480	$14,515,305
ATSI	$0	$20,806,849	$20,806,849	$0	$18,752,111	$18,752,111
BGE	$44,256	$4,896,325	$4,940,581	$0	$4,792,346	$4,792,346
COMED	$0	$36,301,053	$36,301,053	$0	$35,634,009	$35,634,009
DAY	$0	$2,076,492	$2,076,492	$0	$2,064,041	$2,064,041
DUKE	$0	$5,978,363	$5,978,363	$0	$5,806,775	$5,806,775
DOM	$0	$35,657,319	$35,657,319	$0	$34,343,529	$34,343,529
DPL	$125,907	$7,237,606	$7,363,514	$505,278	$7,165,423	$7,670,701
DUQ	$0	$61,158	$61,158	$0	$59,400	$59,400
EKPC	$0	$1,607,696	$1,607,696	$60,515	$1,598,055	$1,658,570
JCPLC	$0	$4,557,838	$4,557,838	$0	$4,257,535	$4,257,535
MEC	$27,249	$4,484,940	$4,512,189	$11,455	$4,201,740	$4,213,195
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$15,342,307	$15,342,307	$0	$15,016,242	$15,016,242
PE	$0	$10,888,933	$10,888,933	$0	$9,174,482	$9,174,482
PEPCO	$0	$6,367,831	$6,367,831	$5,249	$6,060,730	$6,065,979
PPL	$0	$26,930,678	$26,930,678	$0	$25,824,170	$25,824,170
PSEG	$0	$19,962,416	$19,962,416	$0	$19,760,832	$19,760,832
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$19,146,985	$19,146,985	$0	$19,894,518	$19,894,518
Total	$1,005,531	$284,786,353	$285,791,884	$589,322	$273,077,696	$273,667,018

Table 10-65 shows the units which received reactive service credits in the first nine months of 2025.

Table 10-65 Reactive service credits by plant (Total dollars): January through September, 2025

	Jan-Sep 2025	
Zone	Plant	Reactive Service Credits
APS	AP CHAMBERSBURG - GUILFORD CT 12	$1,007
APS	AP CHAMBERSBURG - GUILFORD CT 13	$5,817
DPL	DPL BAYVIEW 1 D	$513
DPL	DPL BAYVIEW 2 D	$4,549
DPL	DPL BAYVIEW 3 D	$3,372
DPL	DPL BAYVIEW 4 D	$3,011
DPL	DPL BAYVIEW 5 D	$3,309
DPL	DPL BAYVIEW 6 D	$4,425
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 1 CT	$25,664
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 2 CT	$6,787
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	$7,386
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 6 CT	$28,592
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 7 CT	$28,657
DPL	DPL CRISFIELD 1 D	$0
DPL	DPL CRISFIELD 2 D	$1
DPL	DPL CRISFIELD 3 D	$1
DPL	DPL CRISFIELD 4 D	$1
DPL	DPL EASTON DIESEL	$381,134
DPL	DPL TASLEY 10 CT	$7,877
EKPC	EKPC COOPER 1 F	$42,019
EKPC	EKPC COOPER 2 F	$18,496
METED	ME MOUNTAIN 2 CT	$11,455
PEPCO	PEP ST CHARLES-KELSON RIDGE 2 CC	$5,249

Table 10-66 shows the settled reactive capability revenue requirements by technology effective on September 1, 2025, for active units.[203] These revenue requirements do not include revenue requirements that were filed but not yet final. The table demonstrates the wide disparity in payments for reactive capability that result from the current cost of service rate case model settlement process.

203 The total amount in the final row of Table 10-66 is the amount that would be paid if the total rate effective on September 1, 2025 were effective for an entire year. The total rates effective on any given day depend on requests made by resource owners in filings to FERC and FERC approval of those rates.

Table 10-66 Total settled reactive revenue requirements by unit type and fuel type for active units[204]: September 1, 2025

Unit Type	Fuel Type	Total Revenue Requirement per Year	MW	Number of Resources	Revenue Requirement per MW-year	Minimum Revenue Requirement per MW-year	Maximum Revenue Requirement per MW-year
CC	Gas	$122,213,638.36	48,906.6	152	$371,800.95	$302.10	$22,500.00
CT	Gas	$44,998,557.53	27,734.0	245	$531,994.39	$103.64	$19,610.84
CT	Oil	$4,034,823.25	2,714.9	98	$143,701.18	$289.74	$4,052.58
Diesel	Oil	$839,703.17	145.3	31	$183,630.75	$395.37	$8,812.75
Diesel	Other - Gas	$1,117,240.13	102.6	12	$118,519.87	$3,984.09	$13,468.38
FC	Gas	$45,000.00	2.3	1	$19,565.22	$19,565.22	$19,565.22
Hydro	Water	$24,401,850.45	6,676.3	53	$254,134.36	$126.37	$23,996.44
Nuclear	Nuclear	$68,243,063.20	32,530.9	31	$75,841.24	$807.91	$7,140.45
Solar	Solar	$4,572,620.48	1,466.9	13	$77,386.09	$705.15	$15,007.81
Steam	Coal	$45,956,273.10	34,811.2	56	$128,165.58	$255.85	$9,804.78
Steam	Gas	$5,801,349.66	5,725.3	17	$19,869.70	$626.53	$3,737.86
Steam	Oil	$2,486,051.94	1,499.3	6	$10,944.78	$1,262.01	$3,211.11
Steam	Other - Solid	$340,000.00	34.0	2	$18,919.11	$8,311.11	$10,608.00
Steam	Wood	$330,830.32	153.0	3	$6,486.87	$2,162.29	$2,162.29
Wind	Wind	$17,987,594.17	4,877.4	38	$154,123.83	$1,860.80	$9,564.74
All		$343,368,595.75	167,380.0	758	$2,051.43	$103.64	$23,996.44

Frequency Control

There are four distinct types of frequency control, distinguished by response timeframe and operational nature: Inertial Response, Primary Frequency Response, Secondary Frequency Control (Regulation), and Tertiary Frequency Control (Primary Reserve).

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to changes in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.
- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins to respond within 10 to 15 seconds and can continue up to an hour. Regulation is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is called primary reserve.

204 For aggregate requirements, in which a single payment is made for the combined output of multiple units, the aggregate requirement was distributed in proportion to unit size for calculating a resource's individual revenue requirement. For wind, solar, and hydro resources, that size is the ELCC. For all other resources, that size is the ICAP.

Primary Frequency Response

Primary Frequency Response ("PFR") is achieved through the use of automatic governors installed on generators. A governor can be either an electronic or mechanical device that increases or decreases a generator's output based on frequency changes in the system. Governors are set to respond to any frequency changes larger than a defined minimum, called a deadband, which is expressed in Hertz (Hz). Governors have a frequency change limit, called droop, which is expressed as a percentage of the frequency change from the optimal 60 Hz (e.g. 2 percent droop equals 0.02 * 60 Hz, or 1.2 Hz). Governor droop changes resource output in proportion to the deviation of frequency once frequency has exceeded the deadband limit. Primary frequency response alone does not restore frequency to the original scheduled value primarily because governor directed changes only occur when frequency is beyond the governor deadband.

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require all newly interconnecting non nuclear generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service. Such equipment must include a governor or equivalent controls with the capability of operating at a maximum five percent droop and ±0.036 Hz deadband (or the equivalent or better).[205] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[206]

PJM evaluates generators' primary frequency capabilities using two to three frequency events per month, with events being chosen based on the criteria that the frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz. Nuclear units, offline units, units with no available headroom/footroom, units assigned regulation, and units with an active eDART ticket for governor outage are not evaluated. The performance of each unit is evaluated, with each event evaluated separately with a responsive/non-responsive pass/fail determination, and then averaged quarterly. A quarterly unit performance of 50 percent or greater is considered responsive.[207]

There are several current issues with PJM's enforcement and evaluation of generations PFR requirements. Despite the 2018 FERC order, PJM has not maintained an accurate, up to date list of all units subject to evaluation. This means that as new units have come online (since approximately 2020), they are not being tested at all during the monthly frequency events. In addition, PJM does not currently have an objective metric to determine what response constitutes a unit passing a test during these frequency events. Instead, the telemetric response of each unit is compared to the frequency conditions during an event, and a judgement is made as to whether or not the unit has adequately responded. Further, this underlying unit data and results of these primary frequency response events are not saved in PJM's databases, so the MMU is not currently able to verify the results of these tests. In the event of a unit's noncompliance, PJM does not have a defined penalty and remediation process.

The MMU recommends that PJM update and maintain a full list of generation resources required to provide PFR, save all of the results and underlying data associated with testing PFR capabilities, develop the metric(s) necessary to objectively evaluate each unit's PFR during events, and create the necessary tariff/manual language to properly enforce the NERC mandated requirements.

The MMU is working with PJM to update PJM's list of units that are subject to evaluation and to develop a set of metrics for monitoring compliance and measuring performance by units subject to Order No. 842.

The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides the ability to cover all costs, including these. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing

205 See 157 FERC ¶ 61,122 (2016).
206 See 164 FERC ¶ 61,224 (2018).
207 See PJM Manual 12: Balancing Operations, § 3.6.2. Rev. 53 (July 24, 2024).

frequency response. PJM rules appropriately require frequency response as a condition to receive interconnection service.[208]

On August 15, 2024, NERC proposed Project 2020-02, a modification to the PRC-029-1 reliability standard, called, "The frequency and voltage ride through requirement for inverter based generating resources ("IBRs")." This proposed standard is intended to address the risk to reliability associated with the rapid adoption of IBRs, by requiring that Category 2 Generator Owner and Generator Operator ("Category 2 GO/GOP") IBRs remain operational during and after defined frequency and voltage excursions.[209] [210] To achieve this, IBRs must continue to deliver predisturbance levels of active and reactive power, and would only be permitted to trip to avoid equipment damage. This proposal was adopted by the NERC board on October 8, 2024.[211] NERC is currently working with the regional entities to register IBRs, with an effective registration date of May 15, 2026.[212] PJM has identified and submitted to NERC a list of 50 units that meet the criteria for Category 2 GO/GOP IBRs.

208 See 164 FERC ¶ 61,224 at P 2 (2018).
209 "Category 2 GO/GOP," is defined as Generator Owners and Generator Operators that, "...own or operate IBRs that: (i) either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, and (ii) are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV." See NERC, "North American Electric Reliability Corporation Inverter-Based Resources Work Plan Progress Update," <https://www.nerc.com/globalassets/who-we-are/legal--regulatory/filings--orders/nerc-filings-to-ferc/2023/ibr-registration-workplan-may-update_signed.pdf> (Accessed November 7, 2025)
210 See NERC, "PRC-029-1," <https://www.nerc.com> (Accessed November 6, 2024).
211 See NERC, "Project 2020-02 Modifications to PRC-024 (Generator Ride-through)," <https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx> (Accessed August 7, 2025).
212 See NERC, "North American Electric Reliability Corporation Inverter-Based Resources Work Plan Progress Update," <https://www.nerc.com/globalassets/who-we-are/legal--regulatory/filings--orders/nerc-filings-to-ferc/2025/ibr-work-plan-filing_october-2025-update_signed.pdf> (Accessed October 31, 2025)

Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

Congestion is not a useful metric for determining whether there is a benefit to building more transmission. Analyses that use congestion to support the need for transmission expansion incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion can actually increase when the transmission capacity between areas with lower cost generation and areas with higher cost generation is expanded but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher can be the difference between what load pays and generation receives, congestion.

For all these reasons, if done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the cost/benefit analysis for transmission projects would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project. There clearly can be benefits to transmission expansion but congestion is not the correct metric for measuring those benefits. The correct metric is the change in production costs which measures the reduction in the reliance on higher cost generation to meet load in the presence of a transmission constraint.

This issue also illustrates the unintended and negative consequences of misunderstanding congestion and FTRs. The unintended result is to overstate the benefits of transmission expansion by not correctly recognizing how congestion dollars should be returned to load. Even in the case where there is only a partial return of congestion to load, the actual return of congestion to load must be accounted for in order to correctly identify the benefits. Ignoring the return of congestion to load from ARRs/FTRs overstates the potential benefits of transmission expansion, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce production costs and therefore the average cost of energy for load.

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution, further illustrating that the relative levels of SMP and LMP are arbitrary.

1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.
2 The difference in losses is not part of congestion.
3 PJM billing examples can be found in *2022 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (The shadow price is the difference between the CLMPs across the transmission constraint.) There can be multiple binding transmission constraints. CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints, or the shadow price. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[4] When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area based on the single higher price at load buses and the total revenue received by generation based on the prices at the generator buses to provide that energy, after virtual bids have been settled. Congestion equals the sum of day-ahead and balancing congestion. The actual incremental cost paid by load in the constrained area is the difference in price (shadow price) times the MW of load served by higher cost local generation. This is also the higher production costs that result from the constraint.

The energy, marginal losses and congestion metrics must be interpreted carefully.

In PJM accounting, the term total congestion refers to net implicit CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

As with congestion, total system energy costs are more precisely termed net system energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[5]

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch

4 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

5 The total congestion and marginal losses for the first 9 months of 2025 were calculated as of October 31, 2025, and are subject to change, based on continued PJM billing updates.

market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP. This means that no particular importance should be assigned to the levels of SMP and CLMP at a bus.

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. For a given market solution, a change in the reference bus does not change the LMP at any bus and does not change total congestion paid by load and does not change the local congestion paid by load at a specific location. Holding aside the marginal loss component of LMP, local congestion is the sum of the total LMP charges to load at the defined set of buses minus the sum of the total LMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location. Local congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. PJM's fast start pricing logic results in pricing run locational marginal prices (PLMP). PLMP is the price that load pays and generators receive in the PJM energy market.

While PLMP is the official settlement price, PJM continues to calculate LMP based on the logic that PJM uses to actually dispatch system resources and used prior to the introduction of fast start to consistently define dispatch and prices. The LMPs from the dispatch run are dispatch run locational marginal prices (DLMP). While the settlement prices are PLMP, settlement MW are based on the dispatch run in the day-ahead market and are metered output in the real-time market.

PJM inappropriately uses artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. The resultant, artificially uniform source dfax and sink dfax of the artificial constraint can be modified, along with the line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day-ahead and real-time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. These artificial constraints have been used to hide uplift costs by making uplift costs negative congestion charges. The use of artificial constraints is an inappropriate use of PJM discretion as the market operator, putting PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $848.0 million or 61.2 percent, from $1,385.8 million in the first nine months of 2024 to $2,233.8 million in the first nine months of 2025.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $985.1 million or 60.9 percent, from $1,618.5 million in the first nine months of 2024 to $2,603.6 million in the first nine months of 2025.
- **Balancing Congestion.** Negative balancing congestion costs increased by $137.1 million, from -$232.7 million in the first nine months of 2024 to -$369.8 million in the first nine months of 2025. Negative balancing explicit charges increased by $45.6 million, from -$148.0 million in the first nine months of 2024 to -$193.6 million in the first nine months of 2025.
- **Real-Time Congestion.** Real-time congestion costs increased by $1,143.6 million, from $1,659.3 million in the first nine months of 2024 to $2,802.9 million in the first nine months of 2025.

- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2025 ranged from $124.5 million in February to $608.9 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Pleasant View Line, Lenox – North Meshoppen Line, Pleasant View – Ashburn Line, the Goose Creek Transformer, and Ashburn – Goose Creek Line.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first nine months of 2025. The number of congestion event hours in the day-ahead energy market was about five times the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency decreased by 1.9 percent from 57,459 congestion event hours in the first nine months of 2024 to 56,377 congestion event hours in the first nine months of 2025.

  Real-time congestion frequency increased by 4.4 percent from 20,748 congestion event hours in the first nine months of 2024 to 21,659 congestion event hours in the first nine months of 2025.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on transformers and lines and increased on interfaces and flowgates.

  The Pleasant View Transformer was the largest contributor to congestion costs in the first nine months of 2025. With $286.5 million in total congestion costs, it accounted for 12.8 percent of the total PJM congestion costs in the first nine months of 2025.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. While CT pricing logic was officially discontinued, PJM continues to use a related logic to force inflexible units and demand response to be on the margin in both real time and day ahead. None of the PJM defined closed loop interfaces were binding in the first nine months of 2024 or 2025.
- **Zonal Congestion.** DOM had the highest zonal congestion costs among all control zones in the first nine months of 2025. DOM had $414.9 million in zonal congestion costs, comprised of $482.06 million in day-ahead congestion costs and -$67.1 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $400.4 million or 57.6 percent, from $695.2 million in the first nine months of 2024 to $1,095.5 million in the first nine months of 2025. The loss MWh in PJM increased by 745.4 GWh or 6.2 percent, from 12,066.6 GWh in the first nine months of 2024 to 12,812.0 GWh in the first nine months of 2025. The loss component of real-time LMP in the first nine months of 2025 was $0.04, compared to $0.03 in the first nine months of 2024.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $404.2 million or 54.2 percent, from $745.3 million in the first nine months of 2024 to $1,149.5 million in the first nine months of 2025.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $3.8 million or 7.6 percent, from -$50.1 million in the first nine months of 2024 to -$53.9 million in the first nine months of 2025.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $146.7 million or 56.8 percent, from $258.5 million in the first nine months of 2024, to $405.2 million in the first nine months of 2025.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2025 ranged from $74.9 million in May to $222.8 million in January.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $253.4 million or 58.3 percent, from -$434.8 million in the first nine months of 2024 to -$688.2 million in the first nine months of 2025.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $255.5 million or 48.9 percent, from -$522.9 million in the first nine months of 2024 to -$778.5 million in the first nine months of 2025.

- **Balancing System Energy Costs.** Balancing system energy costs increased by $17.9 million or 22.7 percent, from $78.7 million in the first nine months of 2024 to $96.5 million in the first nine months of 2025.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first nine months of 2025 ranged from -$137.8 million in January to -$46.4 million in May.

Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and defined capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion costs increased by $848.0 million or 61.2 percent, from $1,385.8 million in the first nine months of 2024 to $2,233.8 million in the first nine months of 2025.

Monthly total congestion costs ranged from $124.5 million in February to $608.9 million in July in the first nine months of 2025.

The current ARR/FTR design does not ensure that load receives the rights to all congestion revenues. The congestion offset provided by ARRs and self-scheduled FTRs in the first four months of the 2025/2026 planning period was 66.6 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first four months of the 2025/2026 planning period, using the rules effective for each planning period, was 68.7 percent. Load has received $5.4 billion less than load should have received from the 2011/2012 planning period through the first four months of the 2025/2026 planning period.

Issues

Artificial Constraints, Closed Loop Interfaces and CT Pricing Logic

PJM has used, and in some cases, continues to use, artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. Some of these artificial constraints, such as CT pricing logic and closed loop interfaces, result in negative congestion charges that are an artifact of the artificial nature of the constraints that cause generation to be paid more than load pays for energy affected by the constraint. PJM also makes use of artificial constraints that function like closed loop interfaces but which result in positive or negative balancing congestion. These constraints are called Real-Time Short-Term Marginal Value Overrides. These constraints are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint through large uniform dfax on the constrained side and small uniform dfax on the unconstrained side. These artificial constraints take the form of interfaces or enforced contingencies (modifications) on existing constraints. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day-ahead and real-time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. This is an inappropriate use of these tools as it puts PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges. One of the side effects of these changes in parameters, besides causing modeling differences between the day-ahead and real-time market, is that the apparent location of the interface or parent constraint can move intraday relative to source and sink points.

While CT pricing logic was officially discontinued by PJM with the implementation of fast start pricing on September 1, 2021, PJM continues to use the same basic logic (Real-Time Short-Term Marginal Value Overrides) to force inflexible units to be on the margin in both real time and day ahead. PJM used CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM used CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM's LMP security constrained pricing logic. The purpose of forcing inflexible units to be marginal is to artificially reduce the uplift associated with the dispatch of inflexible resources.

Through the assumption of artificial flexibility of the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of CT pricing logic forced the affected resource bus LMP to match the marginal offer of the resource. PJM adjusts the constraint limit based on the output of the resource. Sometimes the constraint limit does not match the flows on the constraint, and the constraint violates instead of binding, resulting in prices set by the transmission constraint penalty factor.

In the case of a closed loop interface, all buses within the interface were modeled with a distribution factor (dfax) of 1.0 to the constraint and therefore with the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affected the CLMP of constrained side buses in proportion to their dfax to that constraint.[6] One objective of making inflexible resources marginal was to artificially minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of artificial constraints was and is a source of modeling differences between the day-ahead and real-time markets. When artificial constraints are not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model result in positive or negative balancing congestion.

Failure to model the same constraints in the day-ahead and real-time markets results in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion.

Use of artificial constraints, closed loop interfaces and CT price setting logic requires manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic, like fast start pricing logic that replaced it, force higher cost inflexible units to be marginal.

Like closed loop interfaces and CT pricing logic, some of the artificially enforced constraint results in negative congestion. As a result, more power is produced in the artificial closed loop or constrained area than would result without the artificial constraint. This means that there are more generation credits than load charges in the constrained area. The constrained area exports power, the lower cost generators outside the constrained area are backed down and prices are lower outside the constrained area as a result. All of the generation within the artificially constrained area is paid the higher CLMP, but only a smaller amount of load (in some cases no load) in the constrained area pays this higher CLMP. As a result, load pays less than generation receives in the artificially constrained area. This difference is negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing charges.

6 The constrained side means the higher priced side with a positive CLMP created by the constraint.

Locational Marginal Price (LMP)

Components

PJM uses a distributed load reference bus. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. Some price effects of binding constraints may be included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of system energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[7] The first derivative of total losses with respect to the power flow is marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[8] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to meet the load in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time load-weighted average LMP components for the first nine months of 2008 through 2025.[9]

The real-time load-weighted average LMP increased by $16.21 or 47.2 percent from $34.31 in the first nine months of 2024 to $50.51 in the first nine months of 2025. The real-time load-weighted average congestion component was $0.12 in the first nine months of 2025, compared to $0.07 in the first nine months of 2024. The real-time load-weighted average loss component in the first nine months of 2025 was $0.04, compared to $0.03 in the first nine months of 2024. The real-time load-weighted average system energy component increased by $16.14 or 47.2 percent from $34.21 in the first nine months of 2024 to $50.34 in the first nine months of 2025. Using a load-weighted reference bus, the real-time load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss components used in real-time settlement are not zero.

7 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

8 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

9 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the real-time energy market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the real-time energy market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM wide real-time load-weighted average LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

Table 11-1 Real-time load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2025[10]

(Jan - Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$77.27	$77.15	$0.07	$0.05
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.02	$34.97	$0.04	$0.01
2013	$39.75	$39.72	$0.01	$0.02
2014	$58.60	$58.61	($0.03)	$0.02
2015	$38.94	$38.89	$0.03	$0.02
2016	$29.32	$29.27	$0.04	$0.02
2017	$30.36	$30.32	$0.02	$0.01
2018	$39.43	$39.37	$0.04	$0.02
2019	$27.60	$27.56	$0.02	$0.02
2020	$21.22	$21.19	$0.02	$0.01
2021	$35.68	$35.63	$0.03	$0.02
2022	$77.84	$77.68	$0.10	$0.06
2023	$30.87	$30.80	$0.05	$0.02
2024	$34.31	$34.21	$0.07	$0.03
2025	$50.51	$50.34	$0.12	$0.04

Table 11-2 shows the PJM day-ahead load-weighted average LMP components for the first nine months of 2008 through 2025. The day-ahead load-weighted average LMP increased by $16.03, or 47.4 percent, from $33.85 in the first nine months of 2024 to $49.88 in the first nine months of 2025. The day-ahead load-weighted average congestion component increased by $0.01 from $0.13 in the first nine months of 2024 to $0.14 in the first nine months of 2025. The day-ahead load-weighted average loss component was $0.07 in the first nine months of 2025, compared to $0.07 in the first nine months of 2024. The day-ahead load-weighted average energy component increased by $16.02, or 47.6 percent, from $33.65 in the first nine months of 2024 to $49.67 in the first nine months of 2025. Using a load-weighted reference bus, the day-ahead load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

Table 11-2 Day-ahead load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2025

(Jan - Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$75.96	$76.30	($0.09)	($0.24)
2009	$39.35	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.29	$34.19	$0.12	($0.02)
2013	$39.49	$39.35	$0.14	($0.00)
2014	$59.08	$58.84	$0.26	($0.01)
2015	$39.51	$39.25	$0.28	($0.02)
2016	$29.69	$29.54	$0.17	($0.01)
2017	$30.26	$30.24	$0.04	($0.02)
2018	$38.71	$38.60	$0.12	($0.01)
2019	$27.70	$27.63	$0.08	($0.01)
2020	$20.95	$20.88	$0.07	($0.01)
2021	$35.51	$35.31	$0.17	$0.03
2022	$76.97	$76.47	$0.32	$0.18
2023	$31.90	$31.80	$0.09	$0.01
2024	$33.85	$33.65	$0.13	$0.07
2025	$49.88	$49.67	$0.14	$0.07

10 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 11-3 shows the PJM real-time load-weighted average LMP by constrained and unconstrained hours. A constrained hour is any hour during which one or more facilities are congested.

Table 11-3 Real-time load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2024 through September 2025

	2024		2025	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$43.09	$32.13	$63.62	$39.41
Feb	$24.92	$20.34	$48.92	$41.67
Mar	$23.10	$24.20	$42.11	$0.00
Apr	$27.27	$25.54	$46.14	$21.60
May	$36.74	$18.92	$37.27	$25.96
Jun	$33.68	$15.68	$68.44	$22.42
Jul	$47.67	$18.96	$60.05	$39.23
Aug	$37.24	$17.81	$40.75	$23.95
Sep	$33.09	$15.18	$43.82	$21.96
Oct	$32.52	$19.01		
Nov	$28.52	$26.30		
Dec	$35.03	$18.89		
Avg	$34.24	$21.86	$51.16	$28.77

Table 11-4 shows the monthly comparison of real-time constrained and unconstrained hours from January 2024 and the first nine months of 2025. A constrained hour is any hour during which one or more facilities are congested. There were more real-time constrained hours in the first nine months of 2024 than in the first nine months of 2025.

Table 11-4 Real-time constrained and unconstrained hours by month: January 2024 through September 2025

	2024		2025		Difference	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	721	23	712	32	(9)	9
Feb	686	10	671	1	(15)	(9)
Mar	701	43	743	0	42	(43)
Apr	660	60	696	24	36	(36)
May	708	36	595	149	(113)	113
Jun	704	16	714	6	10	(10)
Jul	707	37	717	27	10	(10)
Aug	669	75	658	86	(11)	11
Sep	652	68	713	7	61	(61)
Oct	690	54				
Nov	629	91				
Dec	741	3				
Total	8,268	516	6,219	332	11	(36)

Zonal Components

The load weighted congestion component of LMPs (CLMPs) provided in the following tables (Table 11-5 and Table 11-6) are not a metric of the amount of congestion paid by load in a zone. The listed CLMPs show whether prices (LMPs) in a zone are higher or lower than the load weighted average price in the PJM system due to transmission constraints.

The real-time components of LMP for each control zone are presented in Table 11-5 for the first nine months of 2024 and 2025. In the first nine months of 2025, DOM had the highest real-time congestion component of LMP, $13.09, and COMED had the lowest real-time congestion component of LMP, -$7.12.

Table 11-5 Zonal real-time load-weighted average LMP components (Dollars per MWh): January through September, 2024 and 2025

	2024 (Jan - Sep)				2025 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
ACEC	$31.01	$35.17	($4.87)	$0.71	$47.19	$52.30	($6.23)	$1.12
AEP	$33.43	$33.78	$0.05	($0.40)	$48.10	$49.42	($0.69)	($0.64)
APS	$34.63	$34.15	$0.37	$0.12	$50.50	$50.32	($0.10)	$0.28
ATSI	$33.78	$33.86	($0.14)	$0.06	$47.53	$49.70	($2.20)	$0.03
BGE	$46.83	$34.84	$10.61	$1.38	$62.73	$51.61	$9.05	$2.07
COMED	$29.08	$34.16	($3.65)	($1.44)	$40.72	$50.07	($7.12)	($2.24)
DAY	$35.47	$34.22	$0.63	$0.62	$48.47	$50.32	($2.47)	$0.62
DOM	$39.78	$34.03	$5.18	$0.57	$64.13	$49.99	$13.09	$1.05
DPL	$36.68	$34.97	$0.63	$1.08	$51.57	$51.99	($2.08)	$1.67
DUKE	$33.74	$34.27	($0.23)	($0.30)	$46.80	$50.33	($2.71)	($0.83)
DUQ	$33.98	$34.10	$0.15	($0.27)	$46.64	$50.09	($2.81)	($0.65)
EKPC	$33.86	$34.68	($0.31)	($0.51)	$48.65	$51.27	($1.51)	($1.11)
JCPLC	$31.14	$35.61	($5.06)	$0.59	$47.59	$52.83	($6.14)	$0.91
MEC	$30.84	$34.24	($3.55)	$0.15	$47.58	$50.68	($3.22)	$0.13
OVEC	$29.82	$31.64	($0.86)	($0.96)	$42.31	$47.00	($3.02)	($1.67)
PE	$33.09	$33.46	($0.65)	$0.28	$49.94	$49.50	$0.00	$0.44
PECO	$30.31	$34.55	($4.39)	$0.14	$44.43	$50.96	($6.77)	$0.25
PEPCO	$42.92	$34.79	$7.09	$1.05	$61.79	$51.44	$8.70	$1.65
PPL	$28.86	$33.98	($4.83)	($0.28)	$43.21	$50.37	($6.79)	($0.38)
PSEG	$30.54	$34.58	($4.54)	$0.50	$46.85	$51.24	($5.21)	$0.82
REC	$32.80	$35.42	($3.12)	$0.50	$51.59	$52.31	($1.56)	$0.84
PJM	$34.31	$34.21	$0.07	$0.03	$50.51	$50.34	$0.12	$0.04

The day-ahead components of LMP for each control zone are presented in Table 11-6 for the first nine months of 2024 and 2025. In the first nine months of 2025, DOM had the highest day-ahead congestion component of LMP, $12.77, and COMED had the lowest day-ahead congestion component of LMP, -$6.71.

Table 11-6 Zonal day-ahead load-weighted average LMP components (Dollars per MWh): January through September, 2024 and 2025

	2024 (Jan - Sep)				2025 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
ACEC	$30.36	$34.47	($5.09)	$0.98	$46.30	$51.35	($6.11)	$1.05
AEP	$32.81	$33.44	($0.14)	($0.49)	$47.73	$49.05	($0.69)	($0.63)
APS	$34.29	$33.45	$0.60	$0.23	$49.21	$49.54	($0.69)	$0.36
ATSI	$33.15	$33.36	($0.32)	$0.11	$47.71	$49.04	($1.48)	$0.15
BGE	$46.10	$34.09	$10.40	$1.61	$62.03	$50.79	$9.01	$2.22
COMED	$28.37	$33.44	($3.40)	($1.67)	$40.47	$49.26	($6.71)	($2.08)
DAY	$34.91	$33.78	$0.59	$0.54	$48.87	$49.61	($1.45)	$0.71
DOM	$40.21	$33.59	$5.81	$0.81	$63.64	$49.62	$12.77	$1.25
DPL	$37.04	$34.67	$0.95	$1.42	$52.38	$51.66	($1.06)	$1.78
DUKE	$33.48	$33.82	$0.05	($0.40)	$47.35	$49.76	($1.69)	($0.72)
DUQ	$33.23	$33.70	($0.23)	($0.24)	$46.24	$49.54	($2.57)	($0.72)
EKPC	$33.24	$34.46	($0.35)	($0.87)	$48.68	$51.59	($1.52)	($1.39)
JCPLC	$29.95	$34.59	($5.43)	$0.79	$46.19	$51.37	($5.92)	$0.74
MEC	$31.03	$33.84	($3.16)	$0.35	$47.77	$49.90	($2.24)	$0.12
OVEC	$28.68	$32.65	($2.78)	($1.19)	$41.61	$43.52	($0.46)	($1.45)
PE	$33.26	$32.94	($0.04)	$0.35	$50.03	$48.46	$1.20	$0.37
PECO	$29.71	$33.85	($4.44)	$0.31	$44.14	$50.19	($6.24)	$0.19
PEPCO	$43.54	$34.37	$7.84	$1.33	$61.37	$50.89	$8.59	$1.90
PPL	$28.74	$33.35	($4.43)	($0.18)	$43.21	$49.77	($5.96)	($0.60)
PSEG	$29.66	$33.90	($4.92)	$0.68	$45.31	$50.10	($5.52)	$0.73
REC	$31.96	$33.93	($2.57)	$0.60	$49.44	$49.96	($1.17)	$0.65
PJM	$33.85	$33.65	$0.13	$0.07	$49.88	$49.67	$0.14	$0.07

Hub Components

The real-time components of LMP for each hub are presented in Table 11-7 for the first nine months of 2024 and 2025.[11]

Table 11-7 Hub real-time average LMP components (Dollars per MWh): January through September, 2024 and 2025

	2024 (Jan - Sep)				2025 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$29.74	$31.41	($0.54)	($1.14)	$41.63	$45.92	($2.56)	($1.73)
AEP-DAY Hub	$30.60	$31.41	($0.30)	($0.51)	$43.56	$45.92	($1.51)	($0.85)
ATSI Gen Hub	$30.75	$31.41	($0.19)	($0.48)	$43.21	$45.92	($1.77)	($0.94)
Chicago Gen Hub	$25.16	$31.41	($4.54)	($1.72)	$35.20	$45.92	($8.07)	($2.66)
Chicago Hub	$26.34	$31.41	($3.79)	($1.28)	$36.18	$45.92	($7.74)	($2.00)
Dominion Hub	$33.84	$31.41	$2.45	($0.03)	$49.60	$45.92	$3.63	$0.04
Eastern Hub	$30.74	$31.41	($1.49)	$0.82	$42.96	$45.92	($4.19)	$1.23
N Illinois Hub	$26.08	$31.41	($3.88)	($1.46)	$36.30	$45.92	($7.35)	($2.27)
New Jersey Hub	$27.55	$31.41	($4.26)	$0.39	$40.91	$45.92	($5.64)	$0.63
Ohio Hub	$30.57	$31.41	($0.35)	($0.50)	$43.76	$45.92	($1.32)	($0.84)
West Interface Hub	$32.00	$31.41	$1.03	($0.45)	$45.79	$45.92	$0.50	($0.63)
Western Hub	$33.36	$31.41	$1.61	$0.33	$47.62	$45.92	$1.28	$0.41

The day-ahead components of LMP for each hub are presented in Table 11-8 for the first nine months of 2024 and 2025.

Table 11-8 Hub day-ahead average LMP components (Dollars per MWh): January through September, 2024 and 2025

	2024 (Jan - Sep)				2025 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$29.13	$30.97	($0.67)	($1.16)	$42.27	$45.54	($1.57)	($1.70)
AEP-DAY Hub	$30.15	$30.97	($0.24)	($0.58)	$43.99	$45.54	($0.77)	($0.79)
ATSI Gen Hub	$30.57	$30.97	($0.02)	($0.37)	$43.87	$45.54	($1.00)	($0.68)
Chicago Gen Hub	$25.21	$30.97	($3.85)	($1.90)	$35.54	$45.54	($7.43)	($2.57)
Chicago Hub	$26.10	$30.97	($3.38)	($1.49)	$36.47	$45.54	($7.14)	($1.93)
Dominion Hub	$33.71	$30.97	$2.61	$0.14	$48.56	$45.54	$2.82	$0.20
Eastern Hub	$30.78	$30.97	($1.23)	$1.05	$43.92	$45.54	($2.89)	$1.27
N Illinois Hub	$25.74	$30.97	($3.56)	($1.67)	$36.37	$45.54	($6.95)	($2.22)
New Jersey Hub	$27.04	$30.97	($4.46)	$0.54	$40.93	$45.54	($5.20)	$0.60
Ohio Hub	$30.14	$30.97	($0.24)	($0.59)	$44.12	$45.54	($0.65)	($0.77)
West Interface Hub	$31.58	$30.97	$0.96	($0.34)	$45.65	$45.54	$0.58	($0.47)
Western Hub	$33.53	$30.97	$2.13	$0.44	$47.67	$45.54	$1.65	$0.48

11 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time, load-weighted, average of the hourly components of LMP.

Congestion

Congestion Accounting

In PJM accounting, total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are not directly attributable to specific participants that are distributed on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution, and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or actual congestion, it merely changes the components of the LMP.

Congestion occurs in the day-ahead and real-time energy markets.[12] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the real-time energy market.

Implicit CLMP charges are the CLMP charges calculated for energy injected or withdrawn at a location. The explicit CLMP charges are the CLMP charges calculated for transactions with a defined source and a sink. For example, implicit CLMP charges are calculated for network load and explicit CLMP charges are calculated for up to congestion transactions (UTCs). Inadvertent CLMP charges are CLMP charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour.

12 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

CLMP charges and CLMP credits are calculated for both the day-ahead and balancing energy markets.

- **Day-Ahead Implicit Load CLMP Charges.** Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid bus CLMP or the CLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation CLMP Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.[13] Day-ahead implicit injection credits are calculated using MW and the generator bus CLMP, the increment offer's bus CLMP or the CLMP at the sink of the purchase transaction.
- **Balancing Implicit Load CLMP Charges.** Balancing implicit withdrawal charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Balancing Implicit Generation CLMP Credits.** Balancing implicit injection credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.

13 Internal bilateral transactions are included in the tariff definitions of Market Participant Energy Injections and Market Participant Energy Withdrawals. The purchase part of an internal bilateral transaction is an injection to the buyer and the sale part of an internal bilateral transaction is a withdrawal to the seller. The tariff (Attachment K) also says market participants will be charged implicit CLMP charges for all Market Participant Energy Withdrawals and will be credited implicit CLMP credits for all Market Participant Energy Injections. The seller of an internal bilateral transaction will be charged implicit CLMP charges at the source and the buyer of an internal bilateral transaction will be credited implicit CLMP credits at the sink. Internal bilateral transaction CLMP credits and charges sum to zero, as the IBT is merely a transfer of ownership injection and withdrawal MW and associated charges and credits between participants, meaning that the sum of all MW and all credits and all charges with and without IBTs are the same.

- **Explicit CLMP Charges.** Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent CLMP Charges.** Inadvertent CLMP charges are charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion accounting calculation equations are in Table 11-9.

Table 11-9 Congestion accounting calculations

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh

PJM billing items include Day-Ahead Transmission Congestion Charges, Day-Ahead Transmission Congestion Credits, Balancing Transmission Congestion Charges, and Balancing Transmission Congestion Credits. Those line items are calculated for each PJM member. The congestion bill shows the CLMP charges or credits collected from the PJM market participants. However, the sum of an individual customer's CLMP credits or charges on the customer's bill is not a measure of the congestion paid by that customer.

The congestion paid by a customer is the difference between what the customer paid for energy and what all network sources of that energy were paid to serve that customer. A load customer's congestion bill, in contrast, merely indicates whether the LMP they paid for their withdrawals is higher or lower than the system energy price due to transmission constraints. The customer's bill does not measure congestion paid by the customer, only how much the customer was charged and credited for their MW positions. The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in CLMP charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation. CLMPs can be both positive and negative and CLMP charges and CLMP credits can be both positive and negative. CLMP charges, positive or negative, are paid by withdrawals and CLMP credits, positive or negative, are paid to injections. Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when

14 PJM Operating Agreement Schedule 1 §3.7.

negative, measure the net congestion credit paid to a participant group. Explicit CLMP charges, when positive, measure the CLMP payment from a PJM member and when negative, measure the CLMP credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs). In all cases, whether positive or negative, CLMP charges and credits merely indicate whether the LMP being paid by withdrawals or credited to injections is higher or lower than the system weighted average price due to binding transmission constraints.

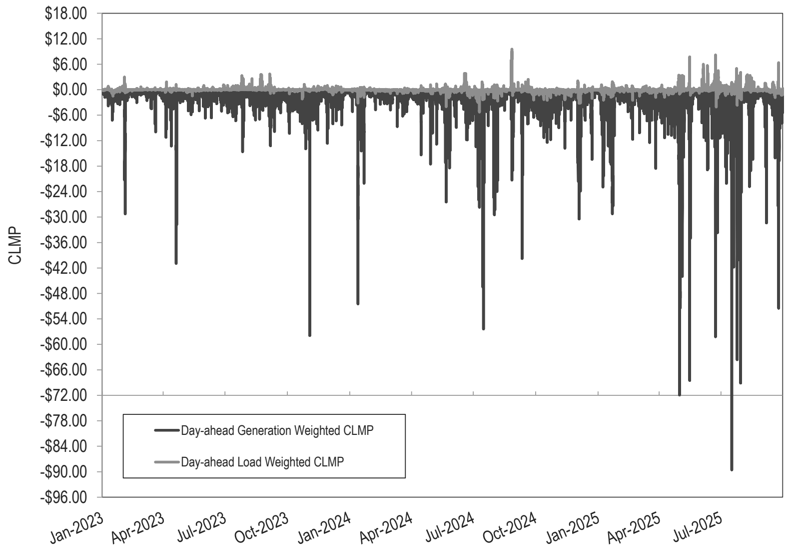
The congestion accounting definitions are misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means only that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding CLMP costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor from the constraint to the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. At the load-weighted reference bus, which represents the load center of the system, the LMP calculation is designed to include no congestion or loss components, but it may include congestion. The load-weighted average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related CLMP charges is logically zero and the small reported differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP, due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP, due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. Due to transmission constraints, the average generation weighted CLMP for generation resources is lower than the LMP at the load-weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation CLMP credits are negative. Figure 11-1 shows the weighted average CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that from January 2023 to September 2025, day-ahead generation weighted CLMPs were generally negative and day-ahead, load weighted CLMPs were generally positive, indicating that load was charged a higher weighted average LMP for energy as a result of transmission constraints than the weighted average LMP generation was paid to provide that energy. This means that total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-12 and Table 11-13). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

15 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: January 2023 through September 2025



Total Congestion

Total congestion costs in PJM in the first nine months of 2025 were $2,233.8 million, comprised of implicit withdrawal charges of $852.8 million, minus implicit injection credits of -$1,472.3 million, plus explicit charges of -$91.2 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy, due to binding transmission constraints.

Table 11-10 shows total congestion for January through September, 2008 through 2025. Total congestion costs in Table 11-10 include congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[16] [17]

Table 11-10 Total congestion costs (Dollars (Millions)): January through September, 2008 through 2025[18]

(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778	NA	$26,979	6.6%
2009	$544	(69.4%)	$19,927	2.7%
2010	$1,134	108.7%	$26,249	4.3%
2011	$875	(22.9%)	$28,836	3.0%
2012	$425	(51.4%)	$22,119	1.9%
2013	$510	19.9%	$25,153	2.0%
2014	$1,705	234.6%	$40,770	4.2%
2015	$1,143	(33.0%)	$33,710	3.4%
2016	$822	(28.1%)	$29,490	2.8%
2017	$455	(44.6%)	$29,510	1.5%
2018	$1,116	145.1%	$37,950	2.9%
2019	$419	(62.5%)	$31,850	1.3%
2020	$396	(5.5%)	$27,070	1.5%
2021	$615	55.1%	$37,520	1.6%
2022	$1,863	203.2%	$66,110	2.8%
2023	$760	(59.2%)	$36,380	2.1%
2024	$1,386	82.2%	$39,070	3.5%
2025	$2,234	61.2%	$57,770	3.9%

CLMP charges and credits are not congestion. CLMP charges and credits reflect marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Table 11-11 shows total congestion by day-ahead and balancing component for January through September, 2008 through 2025.

16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.
17 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

18 In Table 11-10, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

Table 11-11 Total CLMP credits and charges by accounting category (Dollars (Millions)): January through September, 2008 through 2025

	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6
2014	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.2)	$0.0	$1,705.4
2015	$539.3	($783.2)	$24.6	$1,347.1	$11.4	$69.9	($145.6)	($204.1)	$0.0	$1,143.0
2016	$313.0	($529.0)	$35.7	$877.8	$1.9	$20.0	($37.3)	($55.5)	($0.0)	$822.2
2017	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$0.0	$455.4
2018	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$0.0	$1,116.2
2019	$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.3)	$0.0	$419.1
2020	$139.3	($307.2)	$55.9	$502.5	($8.8)	$31.3	($66.3)	($106.3)	$0.0	$396.1
2021	$324.5	($413.3)	$51.6	$789.5	($26.8)	$67.5	($80.6)	($174.9)	$0.0	$614.6
2022	$995.5	($1,178.1)	$109.9	$2,283.5	$9.7	$212.7	($217.3)	($420.3)	($0.0)	$1,863.2
2023	$376.2	($492.3)	$108.8	$977.3	$13.4	$63.4	($166.9)	($216.9)	$0.0	$760.4
2024	$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$0.0	$1,385.8
2025	$844.2	($1,657.0)	$102.4	$2,603.6	$8.5	$184.8	($193.6)	($369.8)	($0.0)	$2,233.8

Charges and Credits versus Congestion: Virtual Transactions, Load and Generation

In PJM's two settlement system, there is a day-ahead market and a real-time, balancing market that make up a market day.

In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtual bids, physical load and generation have net MW at the close of a market day's day-ahead and balancing settlement.

Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day. Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion.

Table 11-12 and Table 11-13 show the total CLMP charges and credits for each transaction type in the first nine months of 2025 and 2024. Table 11-12 shows that in the first nine months of 2025 DECs were paid $25.1 million in CLMP charges in the day-ahead market, were paid $42.1 million in CLMP credits in the balancing energy market, resulting in a net payment of $67.2 million. In the first nine months of 2025, INCs paid $128.5 million in CLMP charges in the day-ahead market, were paid $177.2 million in CLMP credits in the balancing energy market resulting in a net payment of $48.7 million. In the first nine months of 2025, up to congestion (UTCs) paid $99.8 million in CLMP charges in the day-ahead market, were paid $190.2 million in CLMP credits in the balancing market resulting in a total payment of $90.4 million in total CLMP credits.

Table 11-12 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 2025

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($25.1)	$0.0	$0.0	($25.1)	($42.1)	$0.0	$0.0	($42.1)	$0.0	($67.2)
Demand	$110.5	$0.0	$0.0	$110.5	$97.8	$0.0	$0.0	$97.8	$0.0	$208.4
Demand Response	$1.1	$0.0	$0.0	$1.1	($1.5)	$0.0	$0.0	($1.5)	$0.0	($0.4)
Explicit Congestion Only	$0.0	$0.0	$0.7	$0.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7
Explicit Congestion and Loss Only	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.7)
Export	($61.4)	$0.0	($0.5)	($61.9)	($34.8)	$0.0	($0.9)	($35.6)	$0.0	($97.6)
Generation	$0.0	($2,344.2)	$0.0	$2,344.2	$0.0	$31.6	$0.0	($31.6)	$0.0	$2,312.6
Import	$0.0	($6.5)	$0.0	$6.5	$0.0	($13.4)	$0.0	$13.4	$0.0	$20.0
INC	$0.0	($128.5)	$0.0	$128.5	$0.0	$177.2	$0.0	($177.2)	$0.0	($48.7)
Internal Bilateral	$819.3	$822.4	$3.2	($0.0)	($8.2)	($7.9)	$0.0	($0.3)	$0.0	($0.3)
Up to Congestion	$0.0	$0.0	$99.8	$99.8	$0.0	$0.0	($190.2)	($190.2)	$0.0	($90.4)
Wheel In	$0.0	($0.2)	($0.2)	$0.0	$0.0	($2.7)	($2.4)	$0.3	$0.0	$0.3
Wheel Out	($0.2)	$0.0	$0.0	($0.2)	($2.7)	$0.0	$0.0	($2.7)	$0.0	($2.9)
Total	$844.2	($1,657.0)	$102.4	$2,603.6	$8.5	$184.8	($193.6)	($369.8)	$0.0	$2,233.8

Table 11-13 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 2024

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($4.1)	$0.0	$0.0	($4.1)	($3.8)	$0.0	$0.0	($3.8)	$0.0	($7.9)
Demand	$82.6	$0.0	$0.0	$82.6	$48.6	$0.0	$0.0	$48.6	$0.0	$131.2
Demand Response	$0.1	$0.0	$0.0	$0.1	$0.2	$0.0	$0.0	$0.2	$0.0	$0.3
Explicit Congestion Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.0	$0.1	$0.1	$0.0	($0.6)
Export	($46.6)	$0.0	($0.5)	($47.1)	($17.1)	$0.0	($1.4)	($18.5)	$0.0	($65.6)
Generation	$0.0	($1,396.1)	$0.0	$1,396.1	$0.0	$11.5	$0.0	($11.5)	$0.0	$1,384.6
Import	$0.0	($3.5)	$0.0	$3.5	$0.0	($12.6)	$0.0	$12.6	$0.0	$16.1
INC	$0.0	($70.6)	$0.0	$70.6	$0.0	$113.7	$0.0	($113.7)	$0.0	($43.1)
Internal Bilateral	$480.2	$482.0	$1.9	($0.0)	($8.8)	($8.8)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$117.9	$117.9	$0.0	$0.0	($145.0)	($145.0)	$0.0	($27.1)
Wheel In	$0.0	($0.3)	($0.4)	($0.0)	$0.0	($1.7)	($1.6)	$0.0	$0.0	$0.0
Wheel Out	($0.3)	$0.0	$0.0	($0.3)	($1.7)	$0.0	$0.0	($1.7)	$0.0	($2.0)
Total	$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$0.0	$1,385.8

Table 11-14 shows the change in total CLMP credits and charges by transaction type in the first nine months of 2024 and 2025. Total negative CLMP credits to generation increased by $928.0 million, and total CLMP charges to demand increased by $77.2 million. The total CLMP credits to up to congestion transactions (UTCs) decreased by $63.3 million in the first nine months of 2025. Total day-ahead CLMP charges to UTCs decreased by $18.1 million in the first nine months of 2025. Balancing CLMP credits to UTCs decreased by $45.2 million in the first nine months of 2025.

Table 11-14 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): January through September, 2024 to 2025

	Change in CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($21.0)	$0.0	$0.0	($21.0)	($38.3)	$0.0	$0.0	($38.3)	$0.0	($59.3)
Demand	$27.9	$0.0	$0.0	$27.9	$49.2	$0.0	$0.0	$49.2	$0.0	$77.2
Demand Response	$1.1	$0.0	$0.0	$1.1	($1.7)	$0.0	$0.0	($1.7)	$0.0	($0.6)
Explicit Congestion Only	$0.0	$0.0	$0.7	$0.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7
Explicit Congestion and Loss Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.1)
Export	($14.8)	$0.0	($0.0)	($14.8)	($17.7)	$0.0	$0.5	($17.2)	$0.0	($32.0)
Generation	$0.0	($948.2)	$0.0	$948.2	$0.0	$20.2	$0.0	($20.2)	$0.0	$928.0
Import	$0.0	($3.0)	$0.0	$3.0	$0.0	($0.8)	$0.0	$0.9	$0.0	$3.9
INC	$0.0	($57.9)	$0.0	$57.9	$0.0	$63.5	$0.0	($63.5)	$0.0	($5.6)
Internal Bilateral	$339.1	$340.4	$1.3	$0.0	$0.7	$0.9	$0.0	($0.3)	$0.0	($0.3)
Up to Congestion	$0.0	$0.0	($18.1)	($18.1)	$0.0	$0.0	($45.2)	($45.2)	$0.0	($63.3)
Wheel In	$0.0	$0.1	$0.2	$0.0	$0.0	($1.1)	($0.8)	$0.3	$0.0	$0.3
Wheel Out	$0.1	$0.0	$0.0	$0.1	($1.1)	$0.0	$0.0	($1.1)	$0.0	($0.9)
Total	$332.4	($668.6)	($15.9)	$985.1	($8.8)	$82.7	($45.6)	($137.1)	$0.0	$848.0

Table 11-15 compares CLMP credits and charges for each transaction type between the dispatch run and pricing run in the first nine months of 2025. Total CLMP charges to generation decreased by $7.3 million, and total CLMP charges to demand increased by $3.6 million from the dispatch run to the pricing run. The total CLMP credits to DECs decreased by $2.3 million, the total CLMP credits to INCs decreased by $3.4 million and the total CLMP credits to UTCs decreased by $5.1 million from the dispatch run to the pricing run.

Table 11-15 Total CLMP credits and charges by dispatch run and pricing run (Dollars (Millions)): January through September, 2025

	CLMP Credits and Charges (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($25.8)	($39.1)	($64.9)	($25.1)	($42.1)	($67.2)	$0.7	($3.0)	($2.3)
Demand	$110.2	$94.5	$204.8	$110.5	$97.8	$208.4	$0.3	$3.3	$3.6
Demand Response	$1.1	($1.5)	($0.4)	$1.1	($1.5)	($0.4)	$0.1	$0.0	$0.1
Explicit Congestion Only	$0.7	$0.0	$0.7	$0.7	$0.0	$0.7	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	($0.6)	($0.2)	($0.7)	($0.6)	($0.1)	($0.7)	($0.0)	$0.0	($0.0)
Export	($62.2)	($33.8)	($96.0)	($61.9)	($35.6)	($97.6)	$0.3	($1.9)	($1.6)
Generation	$2,345.6	($25.7)	$2,319.9	$2,344.2	($31.6)	$2,312.6	($1.4)	($5.9)	($7.3)
Import	$6.7	$14.5	$21.2	$6.5	$13.4	$20.0	($0.2)	($1.1)	($1.2)
INC	$128.4	($173.7)	($45.3)	$128.5	($177.2)	($48.7)	$0.1	($3.5)	($3.4)
Internal Bilateral	$0.0	($0.3)	($0.3)	($0.0)	($0.3)	($0.3)	($0.0)	($0.0)	($0.0)
Up to Congestion	$98.9	($184.1)	($85.2)	$99.8	($190.2)	($90.4)	$0.9	($6.1)	($5.1)
Wheel In	$0.0	$0.5	$0.5	$0.0	$0.3	$0.3	($0.0)	($0.1)	($0.1)
Wheel Out	($0.2)	($2.6)	($2.8)	($0.2)	($2.7)	($2.9)	$0.0	($0.1)	($0.1)
Total	$2,602.8	($351.4)	$2,251.3	$2,603.6	($369.8)	$2,233.8	$0.8	($18.4)	($17.5)

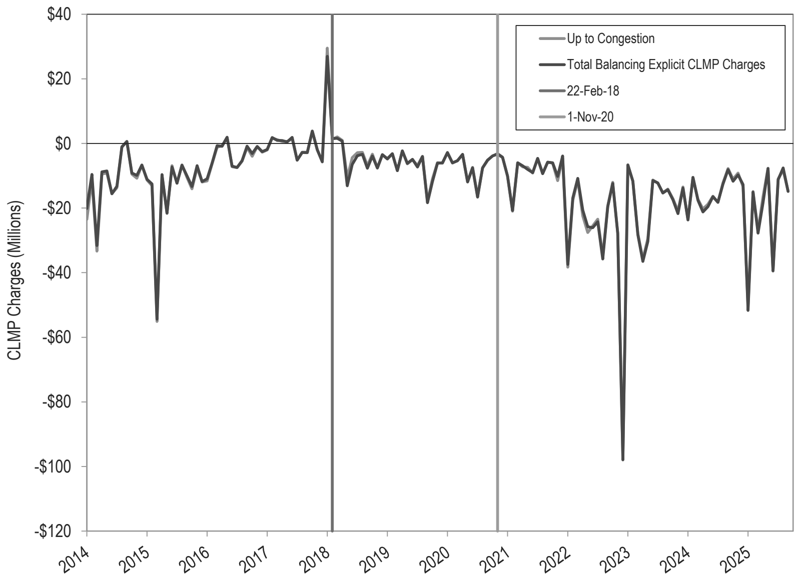
UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from January 2014 through September 2025. Figure 11-2 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In the first nine months of 2025, 98.3 percent (-$190.2 million out of -$193.6 million) of negative balancing explicit CLMP charges was incurred by UTCs and 5.9 percent (-$21.9 out of -$369.8 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-12). The vertical line at February 22, 2018, marks the date on which the FERC order that limited UTC trading to hubs, residual metered load, and interfaces was effective.[19] The vertical line at November 1, 2020, marks the date on which the FERC order that required PJM to allocate uplift to up to congestion transactions was effective.[20]

Negative balancing explicit CLMP charges were substantially higher in December 2022 than in other months as a result of transmission constraint penalty factors in the real-time market in 2022. The total negative balancing explicit CLMP charges on December 7 and 8, 2022, and the Winter Storm Elliott days of December 23 through 26, 2022, were 64.1 percent (-$62.3 million out of -$97.2 million) of total negative balancing explicit CLMP charges in December 2022.

19 For additional information about the FERC order, see the *2022 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
20 172 FERC ¶ 61,046 (2020).

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTCs: January 2014 through September 2025



Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences between market solutions (changes in load and/or generation) and differences between the day-ahead and real-time market models including modeled constraints, the transfer capability (line limits) of the modeled constraints and the differences in deviations between day-ahead and real-time flows that result. The deviations are priced at the real-time LMPs.

For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than is modeled in the day-ahead market. In order to reduce processing time in the presence of large number of virtual bids and offers, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market. Transmission constraints not modeled in the day-ahead market have unlimited transfer capability in the day-ahead market model. The inclusion of the actual, lower transmission capability in the real-time market requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion.[21] The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

As a day-ahead spread bid, UTCs can take advantage of and profit from LMP differences caused by modeling differences between the day-ahead and real-time market. UTCs clear between source and sink points with little or no price difference in the day-ahead market, and settle the resulting deviations at higher real-time price differences in the real-time market. The result is negative balancing congestion caused by and paid to UTCs in the form of CLMP credits. This is an example of false arbitrage because the UTCs cannot cause prices to converge and the profits to decrease. As a result of the FERC order requiring load to pay balancing congestion, load is responsible for paying the balancing congestion caused by UTCs.[22]

Table 11-16 provides an example of how UTCs can profit from differences in day-ahead and real-time models and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with

21 Although it seems counter intuitive, as the amount of low cost generation decreases and the amount of high cost generation increases, the difference between load payments to generation and the payments received by generators goes down. High cost generation receives what load pays.

22 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180 (2016).

the $1 generation at bus A. The constraint between A and B does not bind in day-ahead so the price at A and B is $1. The price spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and B. Total day-ahead congestion, which is the difference between CLMP charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore has deviations at Bus A (-200 MW) and at Bus B (+200 MW). The UTC must buy at bus A at the real-time price and sell at bus B at the real-time price to settle its deviations. The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The UTC must buy 200 MW at A at the real-time price of $1 and sell 200 MW at B at the real-time price of $6. The UTC pays $200 at A and is paid $1,200 at B. The result is a net payment to the UTC of $1,000 in balancing credits.

Table 11-16 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.[23]

23 See 153 FERC ¶ 61,180 (2016).

The UTC did not and could not contribute to price convergence between the day-ahead and real-time market and did not and could not improve efficiency in system dispatch or commitment. The UTC took advantage of the modeling differences between the day-ahead and real-time markets. The UTC did significantly increase payments by load. Load was required to pay the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet real-time load. The differences in modeling would have resulted in only $250 in negative balancing congestion if there had been no UTCs.

Table 11-16 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day-Ahead MW	**Bus A**		**Bus B**	**Total MW**
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	**Bus A**		**Bus B**	**Total Day-Ahead Congestion**
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day-Ahead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	**Bus A**		**Bus B**	**Total Deviations**
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	**Bus A**		**Bus B**	**Balancing Congestion Credits**
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

Zonal and Load Aggregate Congestion

Zonal, and load aggregate, congestion is calculated on a constraint specific basis for a specific location or set of load pricing nodes (a zone or an aggregate). Local congestion is the difference between what load pays for energy and what generation is paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve a specific load, zone or load aggregate. Local congestion calculations account for the total difference between what the specified load pays and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. Congestion is the total congestion payments by load at the buses within a defined area minus total CLMP credits received by generation that supplied that load, given the transmission constraints. Congestion reflects the underlying characteristics of the entire power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of decremental bids and incremental offers and the geographic and temporal distribution of load.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. (The shadow price is the difference between the CLMPs across the constraint.) Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint. Equivalently, total congestion caused by the constraint can also be calculated by the shadow price of the constraint times the market flow on that constraint.

Congestion paid by zonal load is a function of the load share of the total load market flow on all binding constraints. Congestion is the difference between what load pays for energy due to binding transmission constraints and what generation, whether inside or outside the load's zone, is paid to serve that load. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-17 shows day-ahead and balancing congestion by zone and the proportion of congestion resulting from constraints that are external to or internal to each zone, in the first nine months of 2025. Constraints are internal to a zone if both the source and sink points of the constraint are in the zone. DOM had the largest zonal congestion costs among all control zones in the first nine months of 2025. DOM had $414.9 million in zonal congestion costs, comprised of $482.0 million in zonal day-ahead congestion costs and -$67.1 million in zonal balancing congestion costs. The Pleasant View Transformer, the Lenox – North Meshoppen Line, the Pleasant View – Ashburn Line, the Goose Creek Transformer, and the Ashburn – Goose Creek Line contributed $189.8 million, or 25.7 percent of the DOM zonal congestion costs.[24]

Table 11-18 shows congestion costs by zone in the first nine months of 2024.

24 For additional information about the top 20 constraints that affected each zone, see the *2022 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-17 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through September, 2025

CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$8.9	($18.5)	$1.3	$28.6	$0.1	$2.1	($2.0)	($4.0)	$0.9	$23.7	$24.6
AEP	$121.6	($248.8)	$18.2	$388.6	$2.1	$26.8	($30.0)	($54.8)	$30.0	$303.9	$333.8
APS	$59.8	($108.4)	$6.5	$174.7	$0.4	$12.4	($13.3)	($25.3)	$8.5	$140.9	$149.4
ATSI	$65.3	($120.0)	$8.3	$193.6	$2.0	$12.6	($14.1)	($24.7)	$3.0	$165.9	$168.9
BGE	$29.9	($69.9)	$3.5	$103.3	$0.9	$7.1	($7.4)	($13.5)	$5.3	$84.4	$89.7
COMED	$94.0	($168.0)	$9.0	$271.0	$4.4	$18.6	($17.9)	($32.1)	$45.9	$193.0	$238.9
DAY	$13.4	($31.2)	$2.1	$46.7	$0.6	$3.3	($3.7)	($6.4)	$0.0	$40.3	$40.3
DOM	$150.9	($311.3)	$19.8	$482.0	$6.0	$35.6	($37.5)	($67.1)	$227.5	$187.4	$414.9
DPL	$29.7	($40.5)	$2.1	$72.3	($3.7)	$3.9	($3.3)	($10.9)	$20.9	$40.5	$61.4
DUKE	$20.4	($49.8)	$3.0	$73.2	$0.9	$5.3	($5.6)	($10.1)	$3.3	$59.9	$63.2
DUQ	$10.9	($19.3)	$1.2	$31.4	$0.4	$2.5	($2.8)	($4.9)	$0.1	$26.4	$26.5
EKPC	$11.5	($26.9)	$1.8	$40.2	$0.2	$3.1	($3.2)	($6.1)	$0.5	$33.6	$34.1
EXT	$18.9	($29.7)	$2.2	$50.8	$0.1	$6.8	($6.8)	($13.5)	$3.2	$34.1	$37.3
JCPLC	$27.4	($50.0)	$2.8	$80.3	$0.2	$5.6	($5.7)	($11.1)	$0.5	$68.7	$69.1
MEC	$23.9	($28.4)	$1.4	$53.7	($6.9)	$3.6	($3.2)	($13.7)	$1.6	$38.5	$40.1
OVEC	$0.7	($1.8)	$0.9	$3.4	$0.0	$0.2	($0.2)	($0.4)	$0.8	$2.2	$3.0
PE	$18.9	($29.5)	$1.5	$50.0	$0.0	$3.2	($3.5)	($6.7)	$8.8	$34.5	$43.3
PECO	$28.0	($75.4)	$3.9	$107.2	$0.0	$8.0	($8.3)	($16.4)	$4.5	$86.3	$90.8
PEPCO	$29.2	($65.6)	$3.4	$98.3	$0.9	$6.7	($6.9)	($12.7)	$1.0	$84.6	$85.6
PPL	$38.8	($79.4)	$4.7	$122.9	($0.3)	$8.4	($8.8)	($17.5)	$7.8	$97.5	$105.4
PSEG	$40.9	($81.7)	$4.6	$127.2	$0.3	$8.7	($9.0)	($17.4)	$0.7	$109.0	$109.7
REC	$1.3	($2.8)	$0.3	$4.4	$0.0	$0.3	($0.3)	($0.6)	$0.2	$3.6	$3.8
Total	$844.2	($1,657.0)	$102.4	$2,603.6	$8.5	$184.8	($193.6)	($369.8)	$374.9	$1,858.9	$2,233.8

Table 11-18 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through September, 2024

CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$4.6	($10.8)	$1.2	$16.6	$0.1	$1.2	($1.7)	($2.8)	$0.5	$13.3	$13.8
AEP	$75.0	($159.9)	$21.0	$255.9	$3.1	$15.4	($23.2)	($35.4)	$31.9	$188.6	$220.5
APS	$39.0	($65.8)	$7.8	$112.7	$1.2	$6.8	($10.3)	($15.9)	$4.4	$92.4	$96.8
ATSI	$40.4	($82.7)	$10.9	$133.9	$1.7	$8.1	($11.8)	($18.2)	$6.4	$109.3	$115.7
BGE	$22.0	($36.9)	$4.0	$62.9	$1.3	$4.3	($6.0)	($9.0)	$4.2	$49.6	$53.9
COMED	$55.4	($153.0)	$13.6	$222.0	$3.2	$11.3	($13.9)	($22.1)	$80.8	$119.1	$199.9
DAY	$8.2	($19.7)	$2.8	$30.6	$0.5	$2.1	($3.1)	($4.8)	$0.0	$25.9	$25.9
DOM	$84.3	($128.1)	$16.3	$228.6	$3.6	$16.1	($23.5)	($36.0)	$54.6	$138.0	$192.6
DPL	$28.1	($21.3)	$2.6	$52.0	($1.2)	$1.8	($3.2)	($6.3)	$24.4	$21.3	$45.7
DUKE	$13.5	($28.7)	$4.3	$46.4	$0.7	$3.3	($4.8)	($7.3)	$2.3	$36.8	$39.1
DUQ	$7.1	($12.5)	$1.6	$21.1	$0.4	$1.7	($2.4)	($3.7)	$0.5	$16.9	$17.4
EKPC	$7.4	($15.7)	$2.3	$25.5	$0.3	$1.6	($2.6)	($4.0)	$0.0	$21.4	$21.5
EXT	$9.0	($21.6)	$2.5	$33.1	$0.3	$2.7	($4.5)	($6.8)	$1.4	$24.9	$26.3
JCPLC	$13.1	($29.1)	$3.1	$45.2	$0.3	$3.3	($4.7)	($7.8)	$1.1	$36.3	$37.4
MEC	$10.7	($16.4)	$1.8	$28.9	($0.6)	$1.8	($2.6)	($5.0)	$2.8	$21.2	$24.0
OVEC	$0.4	($0.9)	$1.1	$2.3	$0.0	$0.1	($0.2)	($0.3)	$0.9	$1.1	$2.1
PE	$12.4	($18.7)	$2.4	$33.5	$0.2	$1.9	($2.9)	($4.6)	$4.5	$24.4	$28.9
PECO	$16.0	($42.6)	$4.2	$62.8	$0.4	$4.7	($6.7)	($10.9)	$7.5	$44.4	$51.9
PEPCO	$19.1	($29.7)	$3.6	$52.3	$1.0	$3.9	($5.5)	($8.3)	$0.2	$43.8	$44.0
PPL	$24.3	($46.2)	$5.7	$76.2	$0.3	$4.5	($6.9)	($11.0)	$10.6	$54.6	$65.2
PSEG	$20.7	($46.8)	$5.0	$72.5	$0.5	$5.2	($7.3)	($12.0)	$0.4	$60.1	$60.5
REC	$1.2	($1.5)	$0.5	$3.3	$0.0	$0.2	($0.3)	($0.4)	$0.9	$2.0	$2.9
Total	$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$240.4	$1,145.4	$1,385.8

In cases where PJM has used an artificial constraint that causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the artificial constraint is handled as a special case. In the first nine months of 2025, the total congestion costs associated with these special cases were -$1.7 million or -0.0 percent of the total congestion costs. Table 11-17 and Table 11-18 include congestion allocations from these special case artificial constraints.

There are five categories of artificial constraint based specific allocation special cases that can cause negative congestion: congestion associated with artificial constraints with no downstream load bus (no load bus); congestion associated with artificial constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interfaces (closed loop interfaces); congestion associated with CT price setting logic (CT price setting logic); and congestion associated with nontransmission artificial facility constraints in the day-ahead energy market and/or any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors (unclassified).[25]

25 While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals.

Table 11-19 and Table 11-20 show total congestion by type of special case, congestion, and total congestion by zone. Closed loop interfaces and CT pricing logic, and similar artificial constraints employed by PJM to force resources to be marginal, generally result in negative congestion on a constraint specific basis. PJM's use of both the closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in the first nine months of 2024 or 2025. The congestion associated with Real-Time Short-Term Marginal Value Overrides is included in the Normal Constraint Congestion totals.

Table 11-19 CLMP charges and credits and total congestion collected by zone and special case logic (Dollars (Millions)): January through September, 2025

CLMP Credits and Charges (Millions)																	
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.1)	$0.0	$0.0	$0.0	$28.8	$28.6	$0.0	$0.0	$0.0	$0.0	$0.0	($4.0)	($4.0)	$24.6	($0.1)	$0.0
AEP	($0.0)	($1.9)	$0.0	$0.6	$0.0	$389.8	$388.6	$0.0	$0.0	$0.0	$0.0	$0.0	($54.8)	($54.8)	$333.8	($1.3)	($0.0)
APS	($0.0)	($0.9)	$0.0	$0.0	$0.0	$175.6	$174.7	$0.0	$0.0	$0.0	$0.0	$0.0	($25.3)	($25.3)	$149.4	($0.9)	($0.0)
ATSI	($0.0)	($0.6)	$0.0	$0.1	$0.0	$194.1	$193.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($24.7)	($24.7)	$168.9	($0.5)	($0.0)
BGE	($0.0)	($0.5)	$0.0	$0.0	$0.0	$103.7	$103.3	$0.0	$0.0	$0.0	$0.0	$0.0	($13.5)	($13.5)	$89.7	($0.5)	($0.0)
COMED	$0.1	($1.3)	$0.0	$0.9	$0.0	$271.2	$271.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($32.1)	($32.1)	$238.9	($0.2)	($0.0)
DAY	($0.0)	($0.2)	$0.0	$0.0	$0.0	$46.9	$46.7	$0.0	$0.0	$0.0	$0.0	$0.0	($6.4)	($6.4)	$40.3	($0.2)	($0.0)
DOM	($0.0)	($1.8)	$0.0	$0.0	$0.0	$483.7	$482.0	$0.0	$0.0	$0.0	$0.0	$0.0	($67.1)	($67.1)	$414.9	($1.8)	($0.0)
DPL	$0.0	($0.3)	$0.0	$0.0	$0.0	$72.6	$72.3	$0.0	$0.0	$0.0	$0.0	$0.0	($10.9)	($10.9)	$61.4	($0.3)	($0.0)
DUKE	($0.0)	($0.4)	$0.0	$3.3	$0.0	$70.3	$73.2	$0.0	$0.0	$0.0	($0.3)	$0.0	($9.8)	($10.1)	$63.2	$2.6	$0.0
DUQ	($0.0)	($0.2)	$0.0	$0.0	$0.0	$31.6	$31.4	$0.0	$0.0	$0.0	$0.0	$0.0	($4.9)	($4.9)	$26.5	($0.2)	($0.0)
EKPC	($0.0)	($0.3)	$0.0	$0.0	$0.0	$40.5	$40.2	$0.0	$0.0	$0.0	$0.0	$0.0	($6.1)	($6.1)	$34.1	($0.3)	($0.0)
EXT	$3.0	($0.2)	$0.0	$0.0	$0.0	$48.0	$50.8	$0.0	($0.0)	$0.0	$0.0	$0.0	($13.5)	($13.5)	$37.3	$2.8	$0.1
JCPLC	$0.4	($0.4)	$0.0	$0.0	$0.0	$80.2	$80.3	$0.0	$0.0	$0.0	$0.0	$0.0	($11.1)	($11.1)	$69.1	$0.0	$0.0
MEC	($0.0)	($0.2)	$0.0	$0.4	$0.0	$53.6	$53.7	$0.0	$0.0	$0.0	$0.0	$0.0	($13.7)	($13.7)	$40.1	$0.2	$0.0
OVEC	($0.0)	($0.0)	$0.0	$0.8	$0.0	$2.6	$3.4	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	$3.0	$0.8	$0.3
PE	($0.0)	($0.3)	$0.0	$0.1	$0.0	$50.1	$50.0	$0.0	$0.0	$0.0	$0.0	$0.0	($6.7)	($6.7)	$43.3	($0.1)	($0.0)
PECO	$0.0	($0.6)	$0.0	$0.4	$0.0	$107.4	$107.2	$0.0	$0.0	$0.0	$0.0	$0.0	($16.4)	($16.4)	$90.8	($0.2)	($0.0)
PEPCO	($0.0)	($0.4)	$0.0	$0.1	$0.0	$98.6	$98.3	$0.0	$0.0	$0.0	$0.0	$0.0	($12.7)	($12.7)	$85.6	($0.4)	($0.0)
PPL	$0.0	($0.7)	$0.0	$0.1	$0.0	$123.5	$122.9	$0.0	$0.0	$0.0	$0.0	$0.0	($17.5)	($17.5)	$105.4	($0.6)	($0.0)
PSEG	$0.0	($0.6)	$0.0	$0.0	$0.0	$127.8	$127.2	$0.0	$0.0	$0.0	$0.0	$0.0	($17.5)	($17.4)	$109.7	($0.6)	($0.0)
REC	($0.0)	($0.0)	$0.0	$0.0	$0.0	$4.4	$4.4	$0.0	$0.0	$0.0	$0.0	$0.0	($0.6)	($0.6)	$3.8	($0.0)	($0.0)
Total	$3.6	($12.0)	$0.0	$6.9	$0.0	$2,605.1	$2,603.6	$0.0	$0.0	$0.0	($0.3)	$0.0	($369.6)	($369.8)	$2,233.8	($1.7)	($0.0)

Table 11-20 CLMP charges and credits and congestion collected by zone and special case logic (Dollars (Millions)): January through September, 2024

CLMP Credits and Charges (Millions)																	
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Normal Constraint Congestion	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$16.6	$16.6	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.8)	($2.8)	$13.8	($0.0)	(0.3%)
AEP	$0.0	($0.0)	$0.0	$1.1	$0.0	$254.9	$255.9	$0.0	($0.5)	$0.0	($0.0)	$0.0	($35.0)	($35.4)	$220.5	$0.6	0.3%
APS	$0.0	($0.0)	$0.0	$0.0	$0.0	$112.7	$112.7	$0.0	($0.2)	$0.0	($0.0)	$0.0	($15.7)	($15.9)	$96.8	($0.2)	(0.2%)
ATSI	$0.0	($0.0)	$0.0	$0.2	$0.0	$133.7	$133.9	$0.0	($0.2)	$0.0	$0.0	$0.0	($18.0)	($18.2)	$115.7	($0.0)	(0.0%)
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$62.9	$62.9	$0.0	($0.1)	$0.0	($0.0)	$0.0	($8.9)	($9.0)	$53.9	($0.1)	(0.2%)
COMED	$0.6	($0.0)	$0.0	$3.3	$0.0	$218.1	$222.0	$0.0	($0.5)	$0.0	$0.0	$0.0	($21.6)	($22.1)	$199.9	$3.4	1.7%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$30.6	$30.6	$0.0	($0.1)	$0.0	($0.0)	$0.0	($4.7)	($4.8)	$25.9	($0.1)	(0.3%)
DOM	$0.0	($0.0)	$0.0	$0.4	$0.0	$228.3	$228.6	$0.0	($0.4)	$0.0	($0.0)	$0.0	($35.6)	($36.0)	$192.6	($0.1)	(0.1%)
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$52.0	$52.0	$0.0	($0.1)	$0.0	($0.0)	$0.0	($6.2)	($6.3)	$45.7	($0.1)	(0.1%)
DUKE	$0.0	($0.0)	$0.0	$0.0	$0.0	$46.4	$46.4	$0.0	($0.1)	$0.0	($0.0)	$0.0	($7.2)	($7.3)	$39.1	($0.1)	(0.3%)
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$21.1	$21.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.7)	($3.7)	$17.4	($0.1)	(0.3%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$25.5	$25.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.9)	($4.0)	$21.5	($0.1)	(0.2%)
EXT	$1.4	($0.0)	$0.0	$0.0	$0.0	$31.7	$33.1	$0.0	($0.2)	$0.0	($0.0)	$0.0	($6.7)	($6.8)	$26.3	$1.2	4.6%
JCPLC	$1.2	($0.0)	$0.0	$0.0	$0.0	$44.1	$45.2	$0.0	($0.1)	$0.0	($0.0)	$0.0	($7.7)	($7.8)	$37.4	$1.1	2.8%
MEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$28.9	$28.9	$0.0	($0.1)	$0.0	$0.0	$0.0	($4.9)	($5.0)	$24.0	($0.1)	(0.2%)
OVEC	$0.0	($0.0)	$0.0	$0.9	$0.0	$1.4	$2.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.3)	($0.3)	$2.1	$0.9	45.6%
PE	$0.0	($0.0)	$0.0	$0.2	$0.0	$33.3	$33.5	$0.0	($0.1)	$0.0	$0.0	$0.0	($4.5)	($4.6)	$28.9	$0.1	0.4%
PECO	($0.0)	($0.0)	$0.0	$0.1	$0.0	$62.8	$62.8	$0.0	($0.1)	$0.0	($0.0)	$0.0	($10.8)	($10.9)	$51.9	($0.1)	(0.2%)
PEPCO	$0.0	($0.0)	$0.0	$0.1	$0.0	$52.3	$52.3	$0.0	($0.1)	$0.0	($0.0)	$0.0	($8.2)	($8.3)	$44.0	($0.0)	(0.0%)
PPL	$0.1	($0.0)	$0.0	$1.5	$0.0	$74.6	$76.2	$0.0	($0.1)	$0.0	$0.0	$0.0	($10.9)	($11.0)	$65.2	$1.5	2.3%
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$72.5	$72.5	$0.0	($0.2)	$0.0	($0.0)	$0.0	($11.9)	($12.0)	$60.5	($0.2)	(0.3%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.3	$3.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.4)	($0.4)	$2.9	($0.0)	(0.2%)
Total	$3.2	($0.2)	$0.0	$7.8	$0.0	$1,607.7	$1,618.5	$0.0	($3.3)	$0.0	($0.0)	$0.0	($229.4)	($232.7)	$1,385.8	$7.6	0.5%

Table 11-21 show total balancing congestion caused by each of the Real-Time Short-Term Marginal Value Overrides constraints PJM used in the first nine months of 2025 (Table 11-21). The congestion associated with Real-Time Short-Term Marginal Value Overrides is included in the Normal Constraint Congestion totals. Real-Time Short-Term Marginal Value Overrides are artificial transmission contingencies on physical transmission elements. Real-Time Short-Term Marginal Value Overrides temporarily force a generator to be marginal. Real-Time Short-Term Marginal Value Overrides are typically in place for a period of from several hours to a few days. Real-Time Short-Term Marginal Value Overrides are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint through large uniform dfax on the constrained side and small uniform dfax on the unconstrained side. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of significant modeling differences between the day-ahead and real-time market.

Table 11-21 CLMP charges and credits and congestion collected by Real-Time Short-Term Marginal Value Overrides by affected Constraint: January through September, 2025

				CLMP Credits and Charges (Millions)				Percent of Total Congestion Caused by Real-Time Short-Term Marginal Value Overrides
				Balancing				
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	
1	Gardners - Texas Eastern	Line	MEC	($0.3)	$0.1	($0.1)	($0.5)	53.4%
2	Carlisle Pike - Gardners	Line	PE	($0.4)	$0.0	$0.0	($0.4)	46.7%
3	Easton - Emuni	Line	DPL	($0.0)	$0.0	$0.0	$0.0	(0.1%)
	Total			($0.8)	$0.1	($0.0)	($1.0)	100.0%

Fast Start Pricing Effect on Zonal Congestion

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. Table 11-22 compares the congestion costs between the dispatch run and the pricing run in the first nine months of 2025. The table shows that the implementation of fast starting pricing logic caused day-ahead total congestion costs to increase $0.8 million (or 0.0 percent), caused negative balancing congestion costs to decrease $18.4 million (or 5.2 percent), and caused total congestion costs to decrease $17.5 million (or 0.8 percent) from the dispatch run to the pricing run in the first nine months of 2025. In comparing the two pricing results, the same MW, from the dispatch run in the day-ahead market and metered output in the real-time market, are used in the accounting cost calculations.

Table 11-22 Total congestion by dispatch and pricing run (Dollars (Millions)): January through September, 2025

	Congestion Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
ACEC	$28.6	($3.8)	$24.8	$28.6	($4.0)	$24.6	$0.0	($0.2)	($0.2)
AEP	$387.7	($52.0)	$335.8	$388.6	($54.8)	$333.8	$0.8	($2.8)	($1.9)
APS	$174.9	($23.9)	$151.0	$174.7	($25.3)	$149.4	($0.2)	($1.4)	($1.6)
ATSI	$193.6	($23.5)	$170.1	$193.6	($24.7)	$168.9	($0.0)	($1.2)	($1.2)
BGE	$103.1	($12.8)	$90.3	$103.3	($13.5)	$89.7	$0.2	($0.8)	($0.6)
COMED	$270.4	($30.8)	$239.6	$271.0	($32.1)	$238.9	$0.6	($1.3)	($0.7)
DAY	$46.6	($6.1)	$40.5	$46.7	($6.4)	$40.3	$0.1	($0.3)	($0.2)
DOM	$481.8	($63.7)	$418.1	$482.0	($67.1)	$414.9	$0.2	($3.4)	($3.2)
DPL	$72.3	($10.2)	$62.1	$72.3	($10.9)	$61.4	$0.0	($0.7)	($0.7)
DUKE	$73.1	($9.6)	$63.5	$73.2	($10.1)	$63.2	$0.2	($0.5)	($0.3)
DUQ	$31.4	($4.7)	$26.7	$31.4	($4.9)	$26.5	$0.0	($0.2)	($0.2)
EKPC	$40.1	($5.8)	$34.3	$40.2	($6.1)	$34.1	$0.1	($0.3)	($0.2)
EXT	$50.7	($12.9)	$37.8	$50.8	($13.5)	$37.3	$0.1	($0.6)	($0.5)
JCPLC	$80.3	($10.6)	$69.7	$80.3	($11.1)	$69.1	$0.0	($0.6)	($0.6)
MEC	$53.9	($13.3)	$40.5	$53.7	($13.7)	$40.1	($0.1)	($0.3)	($0.4)
OVEC	$3.4	($0.4)	$3.0	$3.4	($0.4)	$3.0	$0.0	($0.0)	($0.0)
PE	$51.0	($6.4)	$44.6	$50.0	($6.7)	$43.3	($1.0)	($0.3)	($1.3)
PECO	$107.1	($15.5)	$91.6	$107.2	($16.4)	$90.8	$0.1	($0.8)	($0.8)
PEPCO	$98.1	($12.0)	$86.2	$98.3	($12.7)	$85.6	$0.1	($0.7)	($0.6)
PPL	$123.1	($16.6)	$106.5	$122.9	($17.5)	$105.4	($0.2)	($0.9)	($1.1)
PSEG	$127.3	($16.5)	$110.8	$127.2	($17.4)	$109.7	($0.1)	($0.9)	($1.1)
REC	$4.4	($0.6)	$3.8	$4.4	($0.6)	$3.8	($0.0)	($0.0)	($0.0)
Total	$2,602.8	($351.4)	$2,251.3	$2,603.6	($369.8)	$2,233.8	$0.8	($18.4)	($17.5)

Monthly Congestion

Table 11-23 shows day-ahead, balancing and inadvertent congestion costs by month for January 2024 through September 2025.

Total negative balancing congestion costs in the first nine months of 2025 were highest in July. The top constraint that contributed to the total balancing congestion costs in the first nine months of 2025 was the AEP – DOM Interface. The constraint accounted for 28.5 percent of the total balancing congestion costs in the first nine months of 2025. The majority (30.2 percent) of negative balancing congestion costs for the AEP – DOM Interface were the result of Generation.

In the first nine months of 2025, total congestion costs were highest in July and lowest in February.

Table 11-23 Monthly congestion costs by market (Dollars (Millions)): January 2024 through September 2025

	Congestion Costs (Millions)							
	2024				2025			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$230.9	($35.0)	$0.0	$196.0	$361.5	($133.8)	($0.0)	$227.8
Feb	$67.8	($14.6)	$0.0	$53.2	$146.5	($22.0)	($0.0)	$124.5
Mar	$99.9	($28.2)	($0.0)	$71.8	$195.5	($44.4)	($0.0)	$151.0
Apr	$108.4	($28.2)	$0.0	$80.1	$185.7	($24.2)	($0.0)	$161.6
May	$199.3	($26.7)	$0.0	$172.6	$253.4	($15.7)	($0.0)	$237.7
Jun	$155.3	($27.5)	$0.0	$127.8	$423.6	($61.5)	($0.0)	$362.2
Jul	$371.5	($41.0)	$0.0	$330.5	$625.4	($16.5)	($0.0)	$608.9
Aug	$256.6	($18.3)	$0.0	$238.3	$176.8	($26.3)	$0.0	$150.4
Sep	$128.7	($13.2)	$0.0	$115.5	$235.1	($25.4)	($0.0)	$209.8
Oct	$137.3	($22.0)	$0.0	$115.2				
Nov	$84.6	($18.5)	$0.0	$66.1				
Dec	$218.2	($31.0)	($0.0)	$187.3				
Total	$2,058.6	($304.2)	$0.0	$1,754.4	$2,603.6	($369.8)	($0.0)	$2,233.8

Figure 11-3 shows PJM monthly total congestion cost for January 2008 through September 2025.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): January 2008 through September 2025

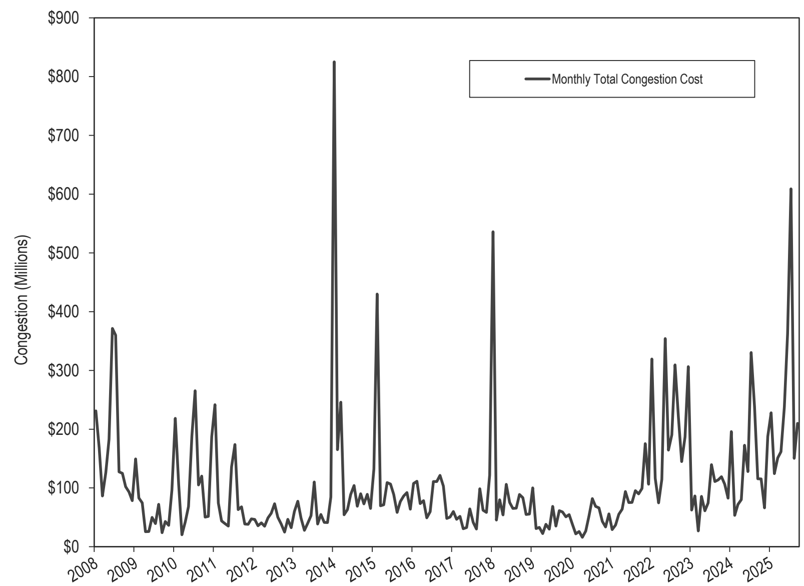


Table 11-24 shows monthly total CLMP credits and charges for each virtual transaction type for January 2024 through September 2025. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-24 show that virtuals were paid, in net, CLMP credits in the first nine months of 2025 and 2024. In the first nine months of 2025, 43.8 percent of the total credits to virtuals went to UTCs, compared to 34.7 percent in the first nine months of 2024. In the first nine months of 2025, the average hourly cleared UTC MW decreased by 10.1 percent, compared to the first nine months of 2024.

Table 11-24 Monthly CLMP charges by virtual transaction type (Dollars (Millions)): January 2024 through September 2025

CLMP Credits and Charges (Millions)											
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2024	Jan	$2.1	($6.6)	($4.6)	$5.5	($10.5)	($4.9)	$16.2	($23.6)	($7.4)	($16.9)
	Feb	($0.6)	$0.5	($0.1)	$6.9	($9.7)	($2.9)	$9.5	($10.5)	($1.0)	($4.0)
	Mar	$0.8	($3.2)	($2.5)	$9.3	($13.8)	($4.5)	$15.3	($17.3)	($2.0)	($8.9)
	Apr	($0.6)	$0.8	$0.3	$14.9	($18.2)	($3.3)	$16.8	($20.3)	($3.4)	($6.4)
	May	($2.8)	$4.1	$1.3	$12.6	($18.0)	($5.4)	$16.6	($18.8)	($2.2)	($6.3)
	Jun	$0.5	$0.7	$1.2	$6.0	($11.1)	($5.1)	$15.3	($16.3)	($1.1)	($4.9)
	Jul	($1.4)	($2.3)	($3.7)	$6.6	($20.3)	($13.7)	$12.0	($18.2)	($6.2)	($23.6)
	Aug	$3.4	($3.8)	($0.4)	$4.7	($5.7)	($1.1)	$10.0	($12.3)	($2.3)	($3.8)
	Sep	($5.4)	$5.9	$0.5	$4.0	($6.3)	($2.3)	$6.2	($7.8)	($1.6)	($3.3)
	Oct	($2.9)	$1.7	($1.2)	$6.2	($11.5)	($5.2)	$9.5	($11.0)	($1.5)	($7.9)
	Nov	($6.4)	$2.7	($3.8)	$12.3	($18.0)	($5.7)	$7.6	($9.2)	($1.6)	($11.1)
	Dec	($17.1)	$8.5	($8.7)	$14.8	($30.0)	($15.3)	$9.5	($13.4)	($3.8)	($27.8)
	Total	($30.5)	$9.0	($21.5)	$103.9	($173.2)	($69.3)	$144.5	($178.6)	($34.1)	($124.9)
2025	Jan	$3.3	($31.1)	($27.8)	$22.3	($35.9)	($13.6)	$16.8	($50.6)	($33.8)	($75.1)
	Feb	($5.2)	$4.2	($1.0)	$12.7	($17.4)	($4.7)	$11.2	($14.9)	($3.7)	($9.4)
	Mar	($2.3)	$2.2	($0.1)	$22.4	($29.5)	($7.1)	$14.2	($27.0)	($12.9)	($20.1)
	Apr	($0.8)	$0.6	($0.2)	$20.8	($26.9)	($6.1)	$6.4	($16.5)	($10.1)	($16.5)
	May	($0.6)	($5.0)	($5.6)	$13.7	($15.2)	($1.5)	$6.7	($7.7)	($0.9)	($8.1)
	Jun	($3.3)	($6.3)	($9.7)	$9.9	($19.9)	($10.0)	$18.9	($39.5)	($20.6)	($40.2)
	Jul	($8.4)	$0.8	($7.6)	$12.0	($13.6)	($1.6)	$8.3	($11.0)	($2.7)	($11.9)
	Aug	$0.1	($10.4)	($10.3)	$4.7	($7.6)	($2.9)	$6.4	($8.2)	($1.9)	($15.1)
	Sep	($7.7)	$2.9	($4.9)	$10.0	($11.1)	($1.2)	$11.0	($14.8)	($3.9)	($9.9)
	Total	($25.1)	($42.1)	($67.2)	$128.5	($177.2)	($48.7)	$99.8	($190.2)	($90.4)	($206.3)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. If two facilities are constrained during an hour, the result is one constrained hour and two congestion event hours. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

In the first nine months of 2025, there were 56,377 day-ahead congestion event hours compared to 57,459 day-ahead congestion event hours in the first nine months of 2024. Of the day-ahead congestion event hours in the first nine months of 2025, only 11,626 (20.6 percent) were also constrained in the real-time energy market (Table 11-26). In the first nine months of 2025, there were 21,659 real-time, congestion event hours compared to 20,748 real-time, congestion event hours in the first nine months of 2024. Of the real-time congestion event hours in the first nine months of 2025, 11,629 (53.7 percent) were also constrained in the day-ahead energy market (Table 11-27).

Congestion Event Hours

Table 11-25 compares the monthly day-ahead and real-time congestion event hours in 2024 and the first nine months of 2025. Day-ahead congestion event hours are significantly greater than real-time congestion event hours.

Table 11-25 Monthly day-ahead and real-time congestion event hours: January 2024 through September 2025

	Day-Ahead Congestion Event Hours		Real-Time Congestion Event Hours	
	2024	2025	2024	2025
Jan	6,003	6,599	2,037	2,493
Feb	5,516	6,213	1,709	2,136
Mar	7,877	8,016	2,527	3,662
Apr	6,464	5,238	2,648	2,446
May	6,833	4,653	2,930	1,692
Jun	6,601	6,727	2,731	2,661
Jul	6,379	6,835	2,397	2,200
Aug	5,822	6,985	1,885	1,618
Sep	5,974	6,985	1,884	2,453
Oct	7,039		2,472	
Nov	5,782		1,808	
Dec	8,015		2,652	
Total	78,305	58,251	27,680	21,361

Table 11-26 and Table 11-27 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the day-ahead energy market, the number of hours during which the facility is also constrained in the real-time energy market are presented in Table 11-26.[26]

Among the hours for which a facility was constrained in the real-time energy market, the number of hours during which the facility was also constrained in the day-ahead energy market are presented in Table 11-27.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first nine months of 2025. The number of congestion event hours in the day-ahead energy market was about five times the number of congestion event hours in the real-time energy market.

In the real-time market, PJM has the ability to model and monitor almost all PJM transmission facilities. In the day-ahead market, PJM can model and monitor only a portion of PJM transmission facilities. This difference in modeling is the basis of false arbitrage and the source of significant virtual profits. While more constraints are modeled and monitored in the PJM real-time market than the day-ahead market, there is significantly more network flow in the day-ahead market than in the real-time market as a result of virtual bids and offers. Virtual bids and offers also contribute to day-ahead market flows that do not align with realized real-time physical flows. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market, despite the fact that only a portion of PJM transmission facilities are modeled in the day-ahead market.

Table 11-26 Congestion event hours (day-ahead against real-time): January through September, 2024 and 2025

	Congestion Event Hours					
	2024 (Jan - Sep)			2025 (Jan - Sep)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	4,898	1,022	20.9%	7,341	1,119	15.2%
Interface	531	120	22.6%	903	131	14.5%
Line	39,297	6,019	15.3%	38,168	7,477	19.6%
Transformer	6,969	548	7.9%	6,052	1,169	19.3%
Other	5,764	2,318	40.2%	3,913	1,730	44.2%
Total	57,459	10,027	17.5%	56,377	11,626	20.6%

Table 11-27 Congestion event hours (real-time against day-ahead): January through September, 2024 and 2025

	Congestion Event Hours					
	2024 (Jan - Sep)			2025 (Jan - Sep)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	3,879	1,022	26.3%	3,239	1,115	34.4%
Interface	224	181	80.8%	351	159	45.3%
Line	12,117	6,110	50.4%	13,616	7,477	54.9%
Transformer	1,164	552	47.4%	2,083	1,119	53.7%
Other	3,364	2,345	69.7%	2,370	1,759	74.2%
Total	20,748	10,210	49.2%	21,659	11,629	53.7%

26 Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single transmission facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one congestion event hour for a given hour in the day-ahead energy market. Similarly in the real-time market a facility may account for more than one congestion event hour within a given hour.

Table 11-28 shows congestion costs by facility voltage class in the first nine months of 2025. Congestion costs in the first nine months of 2025 increased for all facility voltage classes except for 765 kV and 69 kV compared to the first nine months of 2024.

Table 11-28 Congestion summary (By facility voltage): January through September, 2025

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	$2.2	($11.8)	$1.7	$15.7	($1.2)	$2.3	($3.9)	($7.4)	$8.3	164	76
500	$247.9	($484.2)	$17.5	$749.7	$0.1	$70.8	($50.0)	($120.7)	$629.0	2,387	1,187
345	($1.1)	($183.8)	$12.1	$194.7	($12.3)	$12.6	($18.5)	($43.4)	$151.3	5,264	2,142
230	$454.8	($538.1)	$43.4	$1,036.3	$24.8	$34.9	($76.2)	($86.3)	$950.0	18,674	5,856
161	($0.1)	($0.4)	$0.0	$0.4	$0.0	$0.3	($0.7)	($1.0)	($0.6)	17	99
138	$95.9	($197.7)	$25.8	$319.4	($18.8)	$10.8	($38.7)	($68.3)	$251.1	15,629	6,412
115	$29.8	($238.6)	($0.7)	$267.7	$25.5	$49.7	($4.7)	($28.9)	$238.9	10,017	4,847
69	$14.5	($0.7)	$2.4	$17.6	($4.5)	$0.5	($0.9)	($5.9)	$11.7	4,148	443
34	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	27	0
23	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$844.0	($1,655.5)	$102.1	$2,601.6	$13.5	$181.9	($193.5)	($361.9)	$2,239.7	56,327	21,062

Table 11-29 Congestion summary (By facility voltage): January through September, 2024

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	($6.5)	($24.6)	$2.5	$20.6	$1.8	$6.3	($2.2)	($6.8)	$13.8	354	65
500	$132.3	($147.5)	$8.8	$288.5	$3.1	$11.1	($16.1)	($24.0)	$264.5	2,131	778
345	$1.7	($158.8)	$25.4	$185.9	($7.5)	$30.6	($33.6)	($71.7)	$114.2	5,607	2,384
230	$297.9	($371.7)	$37.5	$707.2	$24.8	$21.3	($32.2)	($28.7)	$678.5	17,124	5,665
161	($0.1)	($0.3)	$0.1	$0.2	$0.2	$0.5	($1.3)	($1.6)	($1.4)	79	114
138	$56.3	($181.5)	$34.6	$272.4	($8.5)	$9.2	($49.3)	($67.0)	$205.4	18,608	8,074
115	$6.1	($109.8)	$7.2	$123.1	$5.5	$22.8	($10.4)	($27.7)	$95.4	8,054	3,307
69	$24.1	$5.8	$2.1	$20.4	($1.5)	($0.1)	($1.8)	($3.2)	$17.2	5,476	293
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
23	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	21	0
Unclassified	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$511.8	($988.5)	$118.3	$1,618.5	$17.7	$101.6	($146.9)	($230.8)	$1,387.6	57,454	20,680

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on transformers and lines and increased on flowgates and interfaces in the first nine months of 2025. Congestion event hours on lines decreased by 1,129 congestion event hours from 39,297 day-ahead, congestion event hours in the first nine months of 2024 to 38,168 day-ahead congestion event hours in the first nine months of 2025 (Table 11-30).

Real-time, congestion event hours increased on interfaces, lines and transformers in the first nine months of 2025 (Table 11-31). Lines increased by 1,499 congestion event hours from 12,117 real-time, congestion event hours in the first nine months of 2024 to 13,616 real-time congestion event hours in the first nine months of 2025.

Table 11-30 provides congestion event hour subtotals and congestion cost subtotals comparing the first nine months of 2025 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[27] [28]

Table 11-30 Congestion summary (By facility type): January through September, 2025

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($5.0)	($212.5)	$25.1	$232.6	($5.0)	$3.6	($18.1)	($26.7)	$205.8	7,341	3,239
Interface	$64.7	($158.7)	$12.0	$235.5	($21.5)	$60.8	($32.5)	($114.8)	$120.6	903	351
Line	$503.5	($854.9)	$46.8	$1,405.2	$12.7	$103.8	($117.8)	($209.0)	$1,196.3	38,168	13,616
Transformer	$189.4	($419.9)	$9.8	$619.1	$6.9	$9.6	($16.2)	($18.8)	$600.3	6,052	2,083
Other	$91.5	($11.0)	$8.7	$111.3	$15.5	$7.0	($9.0)	($0.5)	$110.7	3,913	2,370
Unclassified	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	NA	NA
Total	$844.2	($1,657.0)	$102.4	$2,603.6	$8.5	$184.8	($193.6)	($369.8)	$2,233.8	56,377	21,659

Table 11-31 Congestion summary (By facility type): January through September, 2024

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($2.6)	($79.1)	$25.9	$102.5	($3.5)	$6.4	($36.1)	($46.0)	$56.5	4,898	3,879
Interface	$38.3	($56.0)	$5.2	$99.5	($4.1)	$0.9	($10.0)	($15.0)	$84.4	531	224
Line	$233.9	($614.9)	$56.0	$904.9	$3.3	$57.3	($75.6)	($129.6)	$775.3	39,297	12,117
Transformer	$104.7	($148.9)	$16.2	$269.8	$5.3	$20.1	($11.4)	($26.2)	$243.6	6,969	1,164
Other	$137.4	($89.6)	$14.9	$241.8	$16.3	$17.3	($14.9)	($15.9)	$225.9	5,764	3,364
Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$1,385.8	57,459	20,748

27 Unclassified are congestion costs related to nontransmission facility constraints in the day-ahead energy market and any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

28 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Constraint Frequency

Table 11-32 lists the constraints for the first nine months of 2024 and 2025 that were most frequently binding and Table 11-33 shows the constraints which experienced the largest change in congestion event hours from the first nine months of 2024 to the first nine months of 2025. In Table 11-32, constraints are presented in descending order of total day-ahead event hours and real-time event hours in the first nine months of 2025. In Table 11-33, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first nine months of 2024 to the first nine months of 2025.

Table 11-32 Top 25 constraints: January through September, 2024 and 2025

			(Jan - Sep)											
			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2024	2025	Change	2024	2025	Change	2024	2025	Change	2024	2025	Change
1	Lenox - North Meshoppen	Line	3,421	4,601	1,180	2,902	3,890	988	52.0%	70%	18%	44%	59%	15%
2	Nottingham	Other	3,029	2,636	(393)	1,421	1,429	8	46%	40%	(6%)	22%	22%	0%
3	Graceton - Manor	Line	0	1,265	1,265	0	620	620	0%	19%	19%	0%	9%	9%
4	Dune Acres - Michigan City	Flowgate	580	1,807	1,227	0	31	31	9%	28%	19%	0%	0%	0%
5	Kewanee	Other	1,479	1,013	(466)	1,225	803	(422)	22%	15%	(7%)	19%	12%	(6%)
6	Haumesser Road - Steward	Line	1,022	1,232	210	810	452	(358)	16%	19%	3%	12%	7%	(5%)
7	Jordan - West Frankfort	Flowgate	0	803	803	0	614	614	0%	12%	12%	0%	9%	9%
8	Bergen - Hudson	Line	784	1,349	565	0	0	0	12%	21%	9%	0%	0%	0%
9	Dresden	Transformer	363	773	410	200	570	370	6%	12%	6%	3%	9%	6%
10	Dune Acres - Michigan City	Line	0	0	0	440	1,060	620	0%	0%	0%	7%	16%	9%
11	Pleasant View - Ashburn	Line	367	882	515	19	169	150	6%	13%	8%	0%	3%	2%
12	Carlisle Pike - Gardners	Line	457	811	354	101	209	108	7%	12%	5%	2%	3%	2%
13	Easton - Emuni	Line	977	816	(161)	0	158	158	15%	12%	(2%)	0%	2%	2%
14	Prest - Tibb	Flowgate	789	472	(317)	858	495	(363)	12%	7%	(5%)	13%	8%	(5%)
15	Gardners - Texas Eastern	Line	1,429	774	(655)	74	128	54	22%	12%	(10%)	1%	2%	1%
16	Brunner Island - Yorkanna	Line	46	567	521	22	269	247	1%	9%	8%	0%	4%	4%
17	Kokomo - Tipton	Flowgate	54	523	469	97	310	213	1%	8%	7%	1%	5%	3%
18	East Towanda - Hillside	Line	1,143	572	(571)	792	211	(581)	17%	9%	(9%)	12%	3%	(9%)
19	Glendon - Hosensack	Line	5	504	499	0	197	197	0%	8%	8%	0%	3%	3%
20	Otter Creek - Yorkana	Line	171	553	382	0	123	123	3%	8%	6%	0%	2%	2%
21	All Dam - Kittanning	Line	592	502	(90)	76	172	96	9%	8%	(1%)	1%	3%	1%
22	Conastone - Northwest	Line	319	436	117	190	228	38	5%	7%	2%	3%	3%	1%
23	Monroe - Vineland	Line	665	608	(57)	33	42	9	10%	9%	(1%)	1%	1%	0%
24	Hanover - Parrish	Line	76	649	573	0	0	0	1%	10%	9%	0%	0%	0%
25	DoeX530	Transformer	463	644	181	0	0	0	7%	10%	3%	0%	0%	0%

Table 11-33 Top 25 constraints year to year change in occurrence: January through September, 2024 and 2025

			(Jan - Sep)												
			Congestion Event Hours						Percent of Annual Hours						
			Day-Ahead			Real-Time			Day-Ahead			Real-Time			
No.	Constraint	Type	2024	2025	Change	2024	2025	Change	2024	2025	Change	2024	2025	Change	
1	Lenox - North Meshoppen	Line	3,421	4,601	1,180	2,902	3,890	988	52%	70%	18%	44%	59%	15%	
2	Graceton - Manor	Line	0	1,265	1,265	0	620	620	0%	19%	19%	0%	9%	9%	
3	Graceton - Safe Harbor	Line	1,119	0	(1,119)	611	0	(611)	17%	0%	(17%)	9%	0%	(9%)	
4	Jordan - West Frankfort	Flowgate	0	803	803	0	614	614	0%	12%	12%	0%	9%	9%	
5	Yorkana	Other	811	0	(811)	448	0	(448)	12%	0%	(12%)	7%	0%	(7%)	
6	Dune Acres - Michigan City	Flowgate	580	1,807	1,227	0	31	31	9%	28%	19%	0%	0%	0%	
7	Rising - Bondville	Flowgate	683	3	(680)	576	0	(576)	10%	0%	(10%)	9%	0%	(9%)	
8	Sayreville - Sayreville	Line	1,379	141	(1,238)	0	0	0	21%	2%	(19%)	0%	0%	0%	
9	East Towanda - Hillside	Line	1,143	572	(571)	792	211	(581)	17%	9%	(9%)	12%	3%	(9%)	
10	Grabill - Robinson Park	Line	868	0	(868)	158	8	(150)	13%	0%	(13%)	2%	0%	(2%)	
11	Hinshaw - Burr Oak	Flowgate	506	0	(506)	385	0	(385)	8%	0%	(8%)	6%	0%	(6%)	
12	Kewanee	Other	1,479	1,013	(466)	1,225	803	(422)	22%	15%	(7%)	19%	12%	(6%)	
13	Dresden	Transformer	363	773	410	200	570	370	6%	12%	6%	3%	9%	6%	
14	Brunner Island - Yorkanna	Line	46	567	521	22	269	247	1%	9%	8%	0%	4%	4%	
15	Highland - Commerce	Line	501	73	(428)	396	87	(309)	8%	1%	(7%)	6%	1%	(5%)	
16	Glendon - Hosensack	Line	5	504	499	0	197	197	0%	8%	8%	0%	3%	3%	
17	Kokomo - Tipton	Flowgate	54	523	469	97	310	213	1%	8%	7%	1%	5%	3%	
18	Prest - Tibb	Flowgate	789	472	(317)	858	495	(363)	12%	7%	(5%)	13%	8%	(5%)	
19	Salt Springs - Masury	Line	434	37	(397)	303	24	(279)	7%	1%	(6%)	5%	0%	(4%)	
20	Pleasant View - Ashburn	Line	367	882	515	19	169	150	6%	13%	8%	0%	3%	2%	
21	Collins	Transformer	726	65	(661)	0	0	0	11%	1%	(10%)	0%	0%	0%	
22	Dune Acres - Michigan City	Line	0	0	0	440	1,060	620	0%	0%	0%	7%	16%	9%	
23	Gardners - Texas Eastern	Line	1,429	774	(655)	74	128	54	22%	12%	(10%)	1%	2%	1%	
24	Bunsonville - Eugene	Flowgate	0	601	601	0	0	0	0%	9%	9%	0%	0%	0%	
25	Millwood - South Akron	Line	11	434	423	0	156	156	0%	7%	6%	0%	2%	2%	

Top Constraints

The top five constraints by congestion costs contributed $961.4 million, or 43.0 percent, of the total PJM congestion costs in the first nine months of 2025. The top five constraints were the Pleasant View Transformer, the Lenox – North Meshoppen Line, the Pleasant View – Ashburn Line, the Goose Creek Transformer, and the Ashburn – Goose Creek Line. Table 11-34 and Table 11-35 show the top constraints contributing to congestion costs by facility for the first nine months of 2025 and 2024.

The Pleasant View Transformer was the largest contributor to congestion costs in the first nine months of 2025 with $286.5 million and 12.8 percent of total PJM congestion costs.

The Lenox – North Meshoppen Line was the second largest contributor to congestion costs in the first nine months of 2025 with $201.2 million and 9.0 percent of total PJM congestion costs. The day-ahead congestion event hours of the Lenox – North Meshoppen Line increased from 1,180 in the first nine months of 2024 to 4,601 in the first nine months of 2025 and the real-time congestion event hours of the Lenox – North Meshoppen Line increased from 988 in the first nine months of 2024 to 3,890 in the first nine months of 2025 (Table 11-32).

The Pleasant View – Ashburn Line was the third largest contributor to congestion costs in the first nine months of 2025 with $185.9 million and 8.3 percent of the total PJM congestion costs. The day-ahead congestion event hours of the Pleasant View – Ashburn Line increased from 515 in the first nine months of 2024 to 882 in the first nine months of 2025 and the real-time congestion event hours of the Pleasant View – Ashburn Line increased from 150 in the first nine months of 2024 to 169 in the first nine months of 2025 (Table 11-32).

The Goose Creek Transformer was the fourth largest contributor to congestion costs in the first nine months of 2025 with $168.9 million and 7.6 percent of the total PJM congestion costs.

The Ashburn – Goose Creek Line was the fifth largest contributor to congestion costs in the first nine months of 2025 with $118.9 million and 5.3 percent of the total PJM congestion costs.

The AEP – DOM Interface was the largest contributor to negative congestion costs in the first nine months of 2025. The constraint accounted for 28.5 percent of the total balancing congestion costs in the first nine months of 2025.

Table 11-34 Top 25 constraints affecting congestion costs: January through September, 2025[29]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Pleasant View	Transformer	DOM	$94.5	($190.1)	$2.6	$287.1	$8.4	$3.8	($5.2)	($0.6)	$286.5	12.8%
2	Lenox - North Meshoppen	Line	PE	$1.6	($213.3)	($0.5)	$214.4	$38.1	$47.1	($4.2)	($13.2)	$201.2	9.0%
3	Pleasant View - Ashburn	Line	DOM	$104.8	($101.4)	$5.1	$211.3	$12.9	$12.1	($26.1)	($25.4)	$185.9	8.3%
4	Goose Creek	Transformer	DOM	$67.9	($94.6)	$2.6	$165.1	$9.2	$1.9	($3.5)	$3.9	$168.9	7.6%
5	Ashburn - Goose Creek	Line	DOM	$49.7	($64.1)	$3.9	$117.8	$3.6	$1.5	($1.0)	$1.1	$118.9	5.3%
6	Nottingham	Other	PECO	$90.1	$6.1	$7.4	$91.5	$13.5	$3.9	($3.5)	$6.1	$97.6	4.4%
7	AP South	Interface	500	$37.7	($47.4)	$4.0	$89.1	$0.7	$4.1	($2.0)	($5.4)	$83.6	3.7%
8	Dune Acres - Michigan City	Flowgate	MISO	$4.8	($61.4)	$9.5	$75.7	($0.1)	$0.1	($0.3)	($0.6)	$75.1	3.4%
9	Chaparral - Carson	Line	DOM	$7.1	($42.9)	$3.0	$52.9	$0.0	$0.0	$0.0	$0.0	$52.9	2.4%
10	Conastone - Northwest	Line	BGE	$23.3	($19.8)	$0.8	$44.0	$7.2	($4.5)	($3.8)	$8.0	$51.9	2.3%
11	Graceton - Manor	Line	BGE	$36.1	($12.7)	$2.5	$51.3	$7.6	$6.3	($2.0)	($0.7)	$50.6	2.3%
12	Coolspring - Milford	Line	DPL	$6.7	($47.7)	$0.4	$54.8	($7.1)	($2.4)	($0.2)	($4.9)	$49.8	2.2%
13	Dresden	Transformer	COMED	$3.9	($49.6)	$1.2	$54.7	($6.7)	$2.7	($0.4)	($9.8)	$44.9	2.0%
14	Bedington - Black Oak	Interface	500	$13.0	($31.8)	$2.1	$46.9	($0.6)	$1.9	($1.7)	($4.1)	$42.8	1.9%
15	AEP - DOM	Interface	500	$20.0	($37.9)	$6.0	$63.9	($21.7)	$54.9	($28.8)	($105.3)	($41.4)	(1.9%)
16	Bunsonville - Eugene	Flowgate	MISO	$0.5	($35.1)	$0.8	$36.3	$0.0	$0.0	$0.0	$0.0	$36.3	1.6%
17	Idylwood - Clark	Line	DOM	($0.4)	($33.2)	$1.3	$34.1	$0.1	($0.2)	($0.3)	$0.1	$34.1	1.5%
18	Dickerson - Dickerson Station	Line	PEPCO	$27.3	($3.0)	$3.3	$33.6	$2.0	$1.7	($1.1)	($0.8)	$32.8	1.5%
19	Brunner Island - Yorkanna	Line	MEC	$22.3	($8.6)	$1.2	$32.1	$1.7	$1.3	($1.1)	($0.7)	$31.4	1.4%
20	Meridian - Twin Branch	Line	AEP	$1.0	($29.0)	$2.1	$32.1	($2.2)	($1.4)	($1.9)	($2.6)	$29.5	1.3%
21	Dune Acres - Michigan City	Line	MISO	$0.0	$0.0	$0.0	$0.0	($10.7)	$1.4	($16.7)	($28.8)	($28.8)	(1.3%)
22	Beco - Paragon Park	Line	DOM	$11.5	($22.5)	$2.5	$36.5	$2.3	$2.0	($12.6)	($12.3)	$24.1	1.1%
23	Harrowgate - Locks	Line	DOM	$0.0	($20.5)	$1.3	$21.8	($0.6)	$0.2	($1.1)	($1.9)	$19.9	0.9%
24	Jordan - West Frankfort	Flowgate	MISO	($2.9)	($21.9)	$1.8	$20.8	$0.8	$1.1	($1.2)	($1.5)	$19.3	0.9%
25	BCPEP	Interface	PEPCO	$6.4	($12.5)	$0.1	$19.0	$0.0	$0.0	$0.0	$0.0	$19.0	0.9%
	Top 25 Total			$626.8	($1,195.0)	$65.0	$1,886.7	$58.4	$139.4	($118.7)	($199.7)	$1,687.0	75.5%
	All Other Constraints			$217.5	($462.1)	$37.4	$716.9	($49.9)	$45.4	($74.8)	($170.1)	$546.8	24.5%
	Total			$844.2	($1,657.0)	$102.4	$2,603.6	$8.5	$184.8	($193.6)	($369.8)	$2,233.8	100.0%

29 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-35 Top 25 constraints affecting congestion costs: January through September, 2024[30]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Nottingham	Other	PECO	$101.5	$22.2	$11.8	$91.1	$12.1	$2.1	($8.0)	$2.0	$93.1	6.7%
2	Yorkana	Other	MEC	$46.0	($41.6)	$2.5	$90.1	$5.3	$4.9	($2.9)	($2.5)	$87.6	6.3%
3	Lenox - North Meshoppen	Line	PE	$9.7	($75.8)	$6.1	$91.6	$6.9	$22.8	($9.0)	($25.0)	$66.6	4.8%
4	AP South	Interface	500	$31.6	($32.9)	$2.7	$67.1	($0.9)	$0.0	($3.5)	($4.4)	$62.7	4.5%
5	Conastone	Transformer	500	$27.4	($31.4)	$1.8	$60.5	$4.0	$3.3	($2.7)	($1.9)	$58.6	4.2%
6	Pleasant View	Other	DOM	($10.3)	($64.0)	$0.0	$53.7	$1.8	($0.1)	$0.3	$2.2	$55.9	4.0%
7	Chaparral - Carson	Line	DOM	$9.0	($42.6)	$2.7	$54.3	$0.0	$0.0	$0.0	$0.0	$54.3	3.9%
8	Goose Creek	Transformer	DOM	$33.7	($20.8)	$1.2	$55.8	$2.6	$3.5	($2.6)	($3.6)	$52.2	3.8%
9	Graceton - Safe Harbor	Line	BGE	$30.2	($3.0)	$3.2	$36.4	$4.4	$2.2	($3.0)	($0.8)	$35.6	2.6%
10	Braidwood - East Frankfort	Line	COMED	($4.8)	($41.8)	$0.2	$37.2	($0.1)	$2.2	($1.7)	($3.9)	$33.3	2.4%
11	Conastone - Northwest	Line	BGE	$21.0	($10.3)	$2.2	$33.6	$4.4	$3.2	($1.8)	($0.6)	$32.9	2.4%
12	Coolspring - Milford	Line	DPL	$1.2	($34.7)	$0.0	$36.0	($7.9)	($2.2)	($0.1)	($5.8)	$30.2	2.2%
13	Plymouth Meeting - Whitpain	Line	PECO	($0.7)	($31.2)	$0.3	$30.8	$1.4	$1.7	($0.7)	($0.9)	$29.9	2.2%
14	Elk Run D.P. - Rollins Ford	Line	DOM	$0.3	($27.6)	$0.8	$28.7	$0.0	$0.0	$0.0	$0.0	$28.7	2.1%
15	George Washington - Kammer	Line	AEP	($4.9)	($28.0)	$2.1	$25.2	$1.4	($1.2)	($1.4)	$1.2	$26.4	1.9%
16	East Towanda - Hillside	Line	PE	$3.9	($19.9)	$1.7	$25.5	$1.1	$1.3	($1.1)	($1.4)	$24.0	1.7%
17	Cedar Creek - Silver Run	Line	DPL	($3.4)	($27.4)	$0.3	$24.3	($1.2)	($0.5)	$0.1	($0.7)	$23.6	1.7%
18	Juniata	Transformer	500	$10.4	($13.3)	$0.3	$24.0	($0.2)	$0.3	($0.1)	($0.6)	$23.5	1.7%
19	Pleasant View - Ashburn	Line	DOM	$9.9	($11.6)	$1.6	$23.2	$1.9	$1.5	($0.4)	($0.0)	$23.1	1.7%
20	Ashburn - Goose Creek	Line	DOM	$8.9	($10.8)	$0.7	$20.4	$0.0	$0.0	$0.0	$0.0	$20.4	1.5%
21	Fremont - Fremont	Line	AEP	($3.0)	($18.3)	$2.2	$17.5	$0.0	$0.0	$0.0	$0.0	$17.5	1.3%
22	Collins	Transformer	COMED	$1.4	($8.9)	$6.4	$16.7	$0.0	$0.0	$0.0	$0.0	$16.7	1.2%
23	Dickerson - Dickerson Station	Line	PEPCO	$14.9	($2.7)	$0.7	$18.3	$0.8	$1.6	($1.1)	($1.9)	$16.4	1.2%
24	Davis Besse	Other	ATSI	$0.0	$0.0	$0.0	$0.0	($1.8)	$10.9	($2.9)	($15.6)	($15.6)	(1.1%)
25	Charlottesville - Proffit D.P.	Line	DOM	$9.2	($4.2)	$1.2	$14.6	$0.2	($0.5)	($0.5)	$0.2	$14.8	1.1%
	Top 25 Total			$343.1	($580.7)	$52.9	$976.7	$36.3	$57.2	($43.0)	($63.9)	$912.8	65.9%
	All Other Constraints			$168.7	($407.8)	$65.3	$641.8	($18.9)	$44.9	($105.0)	($168.8)	$473.0	34.1%
	Total			$511.8	($988.4)	$118.3	$1,618.5	$17.4	$102.1	($148.0)	($232.7)	$1,385.8	100.0%

30 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Figure 11-4 shows the total hourly congestion costs of the top five constraints in the first nine months of 2025. The Pleasant View Transformer was the top constraint.

Figure 11-4 Top five constraints affecting total congestion costs: January through September, 2025

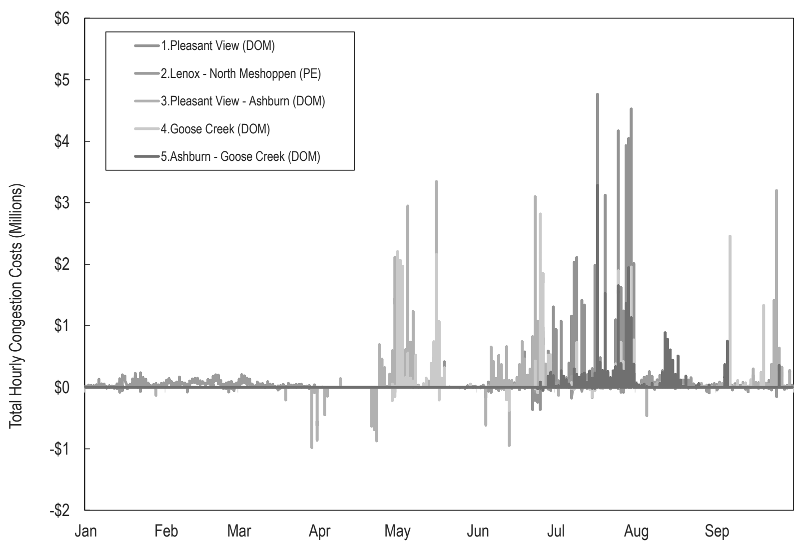


Figure 11-5 shows the total hourly balancing congestion costs of the top five constraints in the first nine months of 2025.

Figure 11-5 Top five constraints affecting balancing congestion costs: January through September, 2025

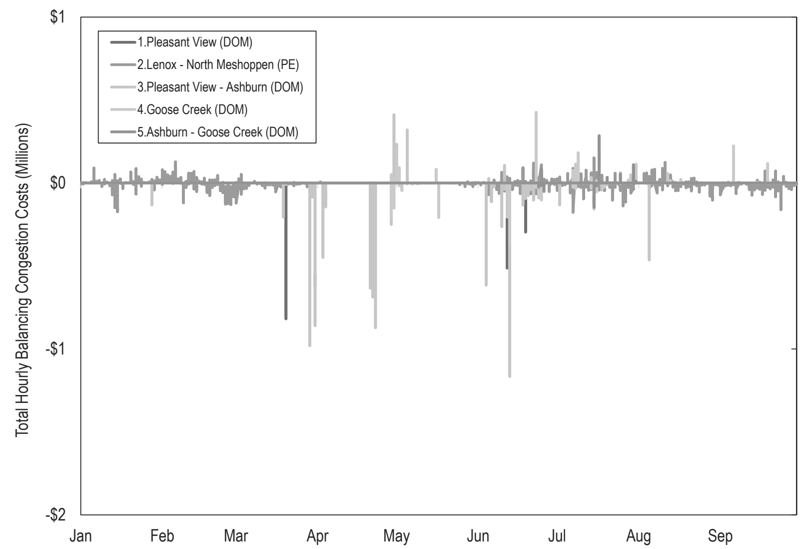


Figure 11-6 shows the total hourly day-ahead congestion costs of the top five constraints in the first nine months of 2025.

Figure 11-6 Top five constraints affecting day-ahead congestion costs: January through September, 2025

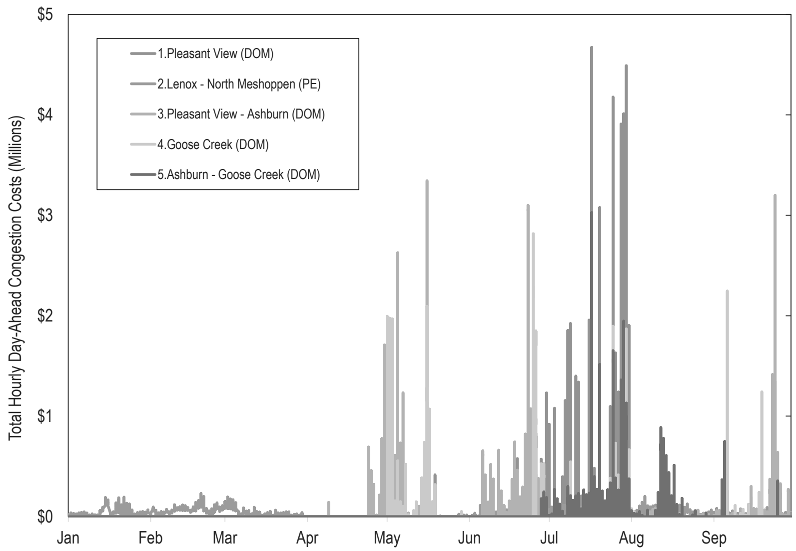


Figure 11-7 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first nine months of 2025.

Figure 11-7 Location of the top 10 constraints by total congestion costs: January through September, 2025

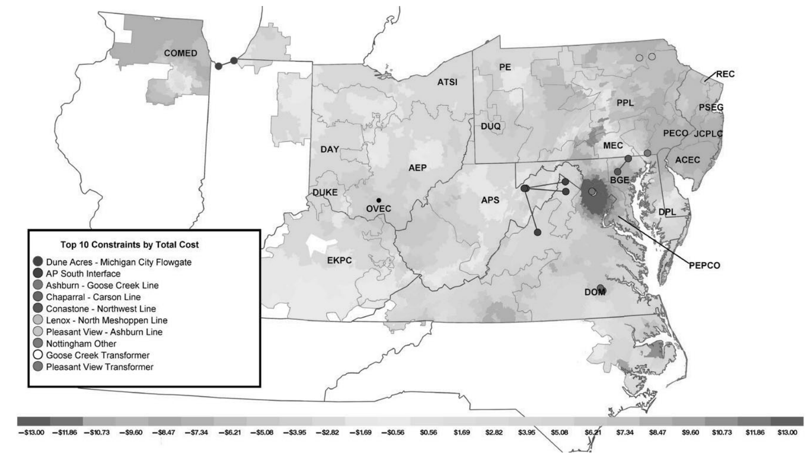


Figure 11-8 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time load-weighted average CLMP in the first nine months of 2025.

Figure 11-8 Location of top 10 constraints by balancing congestion costs: January through September, 2025

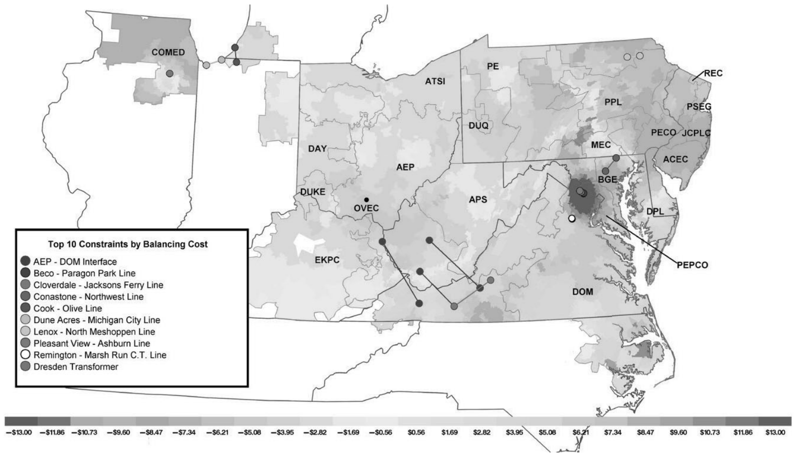
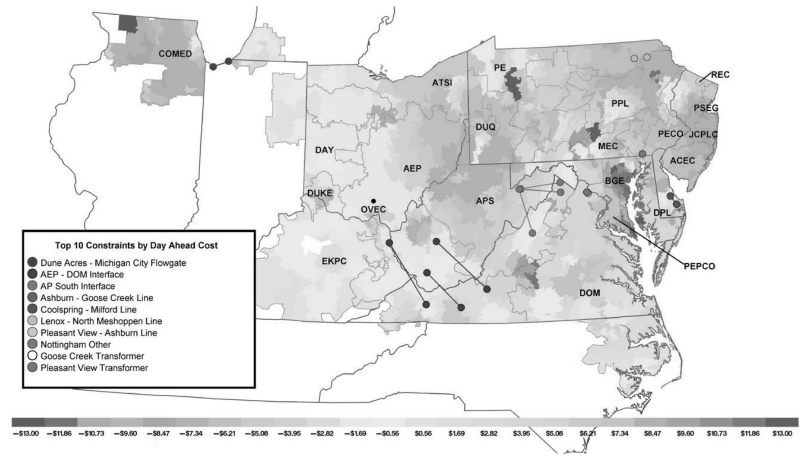


Figure 11-9 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead load-weighted average CLMP in the first nine months of 2025.

Figure 11-9 Location of top 10 constraints by day-ahead congestion costs: January through September, 2025



Comparing Figure 11-8 (Location of the top 10 constraints by balancing congestion costs) and Figure 11-9 (Location of the top 10 constraints by day-ahead congestion costs) shows the significant differences between the day-ahead and real-time markets.

Congestion Event Summary: Impact of Changes in UTC Volumes

UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.[31]

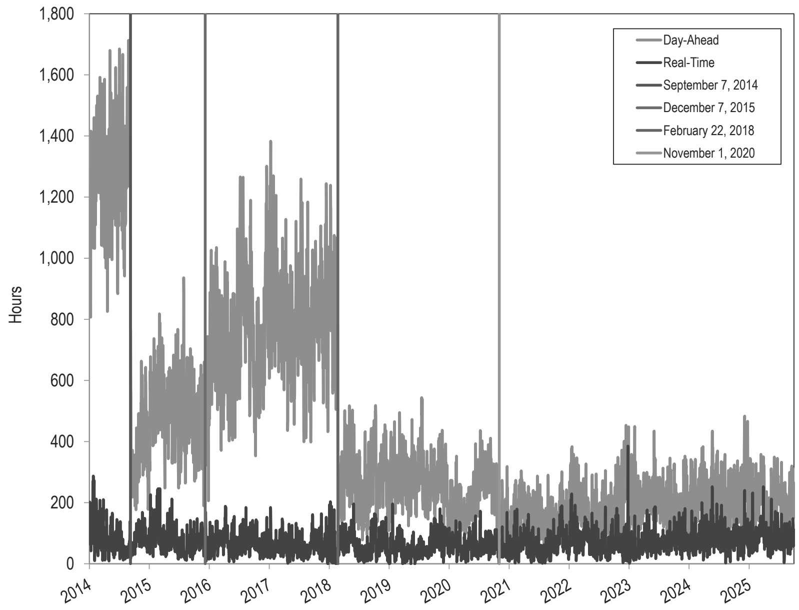
In the first nine months of 2025, the average hourly cleared UTC MW decreased by 10.1 percent, compared to in the first nine months of 2024. Day-ahead congestion event hours decreased by 1.9 percent from 57,459 congestion

31 A series of FERC orders has affected UTC activity which has in turn affected congestion events in the day-ahead market. See Appendix F: Congestion and Marginal Losses.

event hours in the first nine months of 2024 to 56,377 congestion event hours in the first nine months of 2025 (Table 11-26).

Figure 11-10 shows the daily day-ahead and real-time congestion event hours for January 2014 through September 2025.

Figure 11-10 Daily congestion event hours: January 2014 through September 2025



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the day-ahead and real-time energy markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Losses are the difference between what load (withdrawals) pay for energy and what generation (injections) are paid for energy, due to transmission line losses.

Losses increase with distance between sources and sinks and the amount of power moved. Total loss collected (loss surplus) increases with load, holding distance and resistance constant. Every incremental increase in load has to be met with a slightly larger increment of generation. The result is that the total energy losses increase as load increases.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the withdrawal loss charges minus injection loss credits, plus explicit loss charges, incurred in both the day-ahead energy market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[32] Unlike the other categories of marginal loss accounting, inadvertent loss charges are costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[33] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

32 PJM Operating Agreement Schedule 1 §3.7.
33 *Id.*

The accounting definitions can be misleading. Load pays losses. Losses are the difference between what load pays for energy and what generation is paid for energy due to losses. Generation does not pay losses. Some generation receives a price lower than SMP and some generation receives a price greater than SMP due to the MLMP but that does not mean that generation is paying or being paid losses. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP due to losses on the system.

While PJM accounting focuses on MLMPs, the individual MLMP values at any bus are irrelevant to the calculation of total losses. Total losses are the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or losses, it merely changes the components of the LMP.

The MLMP component of LMP is the marginal cost of energy, due to losses associated with serving load at the bus. The MLMP at the load-weighted reference bus is the marginal cost of energy at the load-weighted reference bus (holding the proportion of load at every bus constant). Due to losses, MLMP is non zero at the load reference bus. The LMP at the load reference bus is the system marginal price of energy (SMP) plus the marginal cost of energy due to losses at the reference bus.

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

At the load-weighted reference bus, the LMP includes no congestion component, but does include a loss component. The load weighted average MLMP across all load buses, calculated relative to that reference bus is positive. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses.

Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected by marginal losses. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs.

The residual difference between total marginal loss related load charges (day-ahead and balancing) and marginal loss related generation credits (day-ahead and balancing) after virtual bids have settled their marginal loss related credits and charges for their day-ahead and balancing positions is total loss. That is, losses are the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to losses, after virtual bids marginal loss related charges and credits are settled at the end of the market day. Load is the source of the net loss surplus after generation is paid and virtuals are settled at the end of the market day. Load pays losses. Generation does not pay losses.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the day-ahead and real-time energy markets priced at the marginal loss price component of LMP in the real-time energy market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

The total marginal loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments. The marginal loss surplus is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[34]

Day-Ahead Implicit Load MLMP Charges

- **Day-Ahead Implicit Load MLMP Charges.** Day-ahead implicit load MLMP charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit load MLMP charges are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation MLMP Credits.** Day-ahead implicit generation MLMP credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit generation MLMP credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Implicit Load MLMP Charges.** Balancing implicit load MLMP charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit load MLMP charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Generation MLMP Credits.** Balancing implicit Generation MLMP credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit Generation MLMP credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, which are distributed on a load plus export ratio basis.[35]

Total Marginal Loss Cost

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses.

The total marginal loss cost in PJM for the first nine months of 2025 was $1,095.5 million, which was comprised of implicit withdrawal MLMP charges of $67.5 million minus implicit injection MLMP credits of -$1,037.4 million plus explicit loss charges of -$9.4 million plus inadvertent loss charges of $0.0 million (Table 11-37).

Monthly marginal loss costs in the first nine months of 2025 ranged from $74.9 million in May to $222.8 million in January. Total marginal loss surplus increased in the first nine months of 2025 by $146.7 million or 56.8 percent from $258.5 million in the first nine months of 2024 to $405.2 million in the first nine months of 2025.

Table 11-36 shows the total marginal loss component costs and the total PJM billing for January through September, 2008 through 2025.

34 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 98 (December 17, 2024).

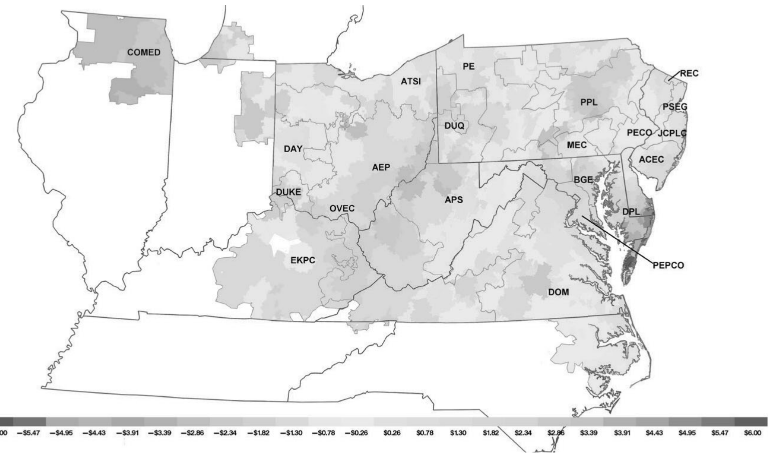
35 PJM Operating Agreement Schedule 1 §3.7.

Table 11-36 Total loss component costs (Dollars (Millions)): January through September, 2008 through 2025[36] [37]

(Jan - Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,049	NA	$26,979	7.6%
2009	$992	(51.6%)	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%
2013	$797	5.2%	$25,153	3.2%
2014	$1,243	56.0%	$40,770	3.0%
2015	$830	(33.3%)	$33,710	2.5%
2016	$542	(34.7%)	$29,490	1.8%
2017	$501	(7.5%)	$29,510	1.7%
2018	$757	51.1%	$37,950	2.0%
2019	$503	(33.6%)	$31,850	1.6%
2020	$349	(30.5%)	$27,070	1.3%
2021	$670	91.9%	$37,520	1.8%
2022	$1,472	119.6%	$66,110	2.2%
2023	$588	(60.0%)	$36,380	1.6%
2024	$695	18.1%	$39,070	1.8%
2025	$1,096	57.6%	$57,770	1.9%

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses. This figure shows the contour map of the day-ahead, load-weighted average MLMP in the first nine months of 2025.

Figure 11-11 Contour map of the day-ahead, load-weighted average MLMP: January through September 2025



Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses. This figure shows the contour map of the real-time, load-weighted average MLMP in the first nine months of 2025.

36 The loss costs include net inadvertent charges.
37 In Table 11-36, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

Figure 11-12 Contour map of the real-time, load-weighted average MLMP: January through September 2025

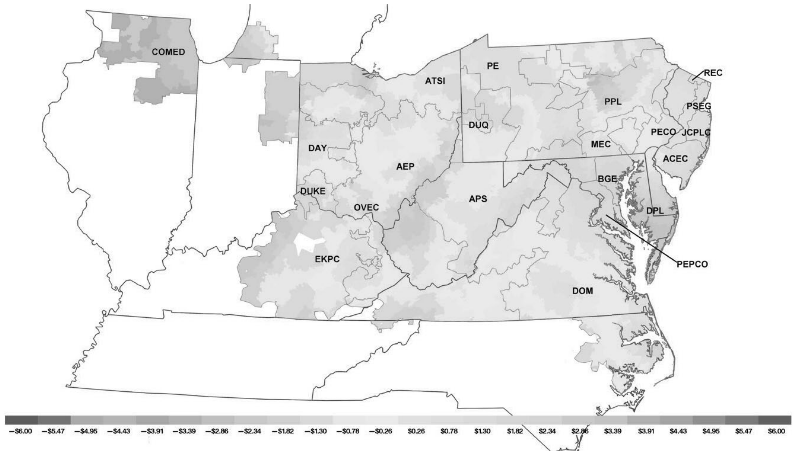


Table 11-37 shows PJM total marginal loss costs by accounting category for January through September, 2008 through 2025. Table 11-38 shows PJM total marginal loss costs by accounting category by market for January through September, 2008 through 2025.

Table 11-37 Total marginal loss costs by accounting category (Dollars (Millions)): January through September, 2008 through 2025

	Marginal Loss Costs (Millions)				
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($210.3)	($2,185.9)	$73.3	$0.0	$2,048.9
2009	($62.0)	($1,028.3)	$26.1	$0.0	$992.4
2010	($73.8)	($1,301.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6
2013	($3.3)	($834.4)	($34.1)	($0.0)	$797.0
2014	($47.6)	($1,343.7)	($52.9)	$0.0	$1,243.1
2015	($26.1)	($872.8)	($16.9)	$0.0	$829.8
2016	($41.7)	($605.4)	($21.8)	($0.0)	$541.9
2017	($38.6)	($568.1)	($28.4)	$0.0	$501.0
2018	($32.7)	($798.6)	($8.9)	$0.0	$757.0
2019	($35.5)	($550.1)	($12.0)	$0.0	$502.7
2020	($25.8)	($387.4)	($12.4)	$0.0	$349.2
2021	$3.3	($673.5)	($6.7)	$0.0	$670.2
2022	$132.6	($1,373.8)	($34.3)	($0.0)	$1,472.0
2023	$8.5	($587.6)	($7.7)	$0.0	$588.5
2024	$72.1	($629.0)	($6.0)	$0.0	$695.2
2025	$67.5	($1,037.4)	($9.4)	($0.0)	$1,095.5

Table 11-38 Total marginal loss costs by market (Dollars (Millions)): January through September, 2008 through 2025

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($132.3)	($2,133.4)	$100.8	$2,101.8	($77.9)	($52.5)	($27.4)	($52.9)	$0.0	$2,048.9
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.9	($2.6)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$20.6	$5.6	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6
2013	($30.3)	($857.9)	$44.0	$871.6	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$797.0
2014	($95.5)	($1,380.8)	$62.7	$1,347.9	$47.9	$37.1	($115.6)	($104.8)	$0.0	$1,243.1
2015	($47.0)	($883.1)	$24.7	$860.8	$20.9	$10.3	($41.6)	($31.0)	$0.0	$829.8
2016	($48.4)	($606.0)	$37.8	$595.4	$6.6	$0.5	($59.5)	($53.4)	($0.0)	$541.9
2017	($45.9)	($568.9)	$43.1	$566.0	$7.3	$0.8	($71.5)	($65.0)	$0.0	$501.0
2018	($38.5)	($790.8)	$28.6	$780.9	$5.8	($7.8)	($37.5)	($23.9)	$0.0	$757.0
2019	($37.4)	($547.8)	$32.2	$542.6	$1.9	($2.3)	($44.2)	($39.9)	$0.0	$502.7
2020	($27.8)	($388.8)	$30.5	$391.5	$2.0	$1.4	($42.9)	($42.3)	$0.0	$349.2
2021	$2.0	($668.7)	$24.7	$695.4	$1.3	($4.9)	($31.4)	($25.2)	$0.0	$670.2
2022	$136.8	($1,371.2)	$65.6	$1,573.6	($4.2)	($2.6)	($99.9)	($101.5)	($0.0)	$1,472.0
2023	$8.0	($585.1)	$53.9	$646.9	$0.6	($2.6)	($61.5)	($58.4)	$0.0	$588.5
2024	$70.8	($631.6)	$42.9	$745.3	$1.3	$2.6	($48.9)	($50.1)	$0.0	$695.2
2025	$67.1	($1,035.7)	$46.7	$1,149.5	$0.4	($1.7)	($56.1)	($53.9)	($0.0)	$1,095.5

Table 11-39 and Table 11-40 show PJM accounting based total loss costs for each transaction type in the first nine months of 2025 and 2024.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transactions. In the first nine months of 2025, DECs were paid $6.6 million in MLMP credits in the day-ahead market, paid $10.0 million in MLMP in the balancing energy market and paid $3.3 million in total MLMP charges. In the first nine months of 2025, INCs paid $33.9 million in MLMP charges in the day-ahead market, were paid $38.0 million in MLMP credits in the balancing energy market and were paid $4.0 million in total MLMP credits. In the first nine months of 2025, up to congestion paid $48.4 million in MLMP charges in the day-ahead market, were paid $55.0 million in MLMP credits in the balancing energy market and received $6.6 million in total MLMP credits.

Table 11-39 Total loss costs by transaction type (Dollars (Millions)): January through September, 2025

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($6.6)	$0.0	$0.0	($6.6)	$10.0	$0.0	$0.0	$10.0	$0.0	$3.3
Demand	$52.0	$0.0	$0.0	$52.0	$12.4	$0.0	$0.0	$12.4	$0.0	$64.4
Demand Response	$0.4	$0.0	$0.0	$0.4	($0.3)	$0.0	$0.0	($0.3)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($1.9)	($1.9)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($2.0)
Export	($24.8)	$0.0	($0.2)	($25.0)	($17.1)	$0.0	($0.7)	($17.8)	$0.0	($42.9)
Generation	$0.0	($1,045.5)	$0.0	$1,045.5	$0.0	($15.6)	$0.0	$15.6	$0.0	$1,061.1
Import	$0.0	($2.9)	$0.0	$2.9	$0.0	($19.7)	$0.0	$19.7	$0.0	$22.6
INC	$0.0	($33.9)	$0.0	$33.9	$0.0	$38.0	$0.0	($38.0)	$0.0	($4.0)
Internal Bilateral	$46.2	$46.7	$0.5	($0.0)	($4.5)	($4.4)	$0.0	($0.1)	$0.0	($0.1)
Up to Congestion	$0.0	$0.0	$48.4	$48.4	$0.0	$0.0	($55.0)	($55.0)	$0.0	($6.6)
Wheel In	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.3)
Total	$67.1	($1,035.7)	$46.7	$1,149.5	$0.4	($1.7)	($56.1)	($53.9)	$0.0	$1,095.5

Table 11-40 Total loss costs by transaction type (Dollars (Millions)): January through September, 2024

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($4.1)	$0.0	$0.0	($4.1)	$6.2	$0.0	$0.0	$6.2	$0.0	$2.2
Demand	$47.0	$0.0	$0.0	$47.0	$7.5	$0.0	$0.0	$7.5	$0.0	$54.5
Demand Response	$0.1	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.0	($0.1)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($1.3)	($1.3)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($1.3)
Export	($14.0)	$0.0	($0.2)	($14.2)	($8.3)	$0.0	($0.8)	($9.1)	$0.0	($23.3)
Generation	$0.0	($646.2)	$0.0	$646.2	$0.0	($11.0)	$0.0	$11.0	$0.0	$657.2
Import	$0.0	($2.6)	$0.0	$2.6	$0.0	($9.6)	$0.0	$9.6	$0.0	$12.3
INC	$0.0	($25.0)	$0.0	$25.0	$0.0	$27.3	$0.0	($27.3)	$0.0	($2.3)
Internal Bilateral	$41.8	$42.2	$0.4	($0.0)	($4.1)	($4.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$44.0	$44.0	$0.0	$0.0	($47.8)	($47.8)	$0.0	($3.7)
Wheel In	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.3)	($0.3)	$0.0	($0.3)
Total	$70.8	($631.6)	$42.9	$745.3	$1.3	$2.6	($48.9)	($50.1)	$0.0	$695.1

Table 11-41 compares MLMP credits and charges for each transaction type between the dispatch run and pricing run in the first nine months of 2025. Total MLMP charges to generation increased by $2.0 million, and total MLMP charges to demand increased by $1.2 million from the dispatch run to the pricing run. The total MLMP charges to DECs increased by $0.9 million, the total MLMP credits to INCs decreased by $2.9 million and the total CLMP credits to UTCs decreased by $4.6 million from the dispatch run to the pricing run.

Table 11-41 Total loss costs by dispatch and pricing run (Dollars (Millions)): January through September, 2025

	Marginal Loss Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($6.6)	$9.1	$2.5	($6.6)	$10.0	$3.3	($0.0)	$0.9	$0.9
Demand	$51.9	$11.3	$63.2	$52.0	$12.4	$64.4	$0.1	$1.1	$1.2
Demand Response	$0.4	($0.3)	$0.1	$0.4	($0.3)	$0.0	$0.0	($0.0)	($0.0)
Explicit Congestion and Loss Only	($1.9)	($0.1)	($2.0)	($1.9)	($0.1)	($2.0)	($0.0)	($0.0)	($0.0)
Export	($25.0)	($16.5)	($41.5)	($25.0)	($17.8)	($42.9)	($0.0)	($1.3)	($1.4)
Generation	$1,044.0	$15.1	$1,059.1	$1,045.5	$15.6	$1,061.1	$1.5	$0.5	$2.0
Import	$2.9	$18.1	$21.0	$2.9	$19.7	$22.6	($0.0)	$1.6	$1.6
INC	$33.9	($35.0)	($1.1)	$33.9	($38.0)	($4.0)	$0.0	($3.0)	($2.9)
Internal Bilateral	($0.0)	($0.1)	($0.1)	$0.0	($0.1)	($0.1)	$0.0	($0.0)	($0.0)
Up to Congestion	$48.4	($50.4)	($2.1)	$48.4	($55.0)	($6.6)	$0.0	($4.6)	($4.6)
Wheel In	($0.1)	($0.2)	($0.3)	($0.1)	($0.2)	($0.3)	($0.0)	($0.0)	($0.0)
Total	$1,147.9	($49.1)	$1,098.8	$1,149.5	($53.9)	$1,095.5	$1.6	($4.8)	($3.2)

Monthly Marginal Loss Costs

Table 11-42 shows a monthly summary of marginal loss costs by market type for January 2024 through September 2025.

Table 11-42 Monthly marginal loss costs (Millions): January 2024 through September 2025

	Marginal Loss Costs (Millions)							
	2024				2025			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$137.5	($9.5)	$0.0	$128.1	$233.1	($10.4)	($0.0)	$222.8
Feb	$52.0	($4.7)	$0.0	$47.3	$121.0	($5.1)	($0.0)	$115.9
Mar	$46.7	($5.1)	($0.0)	$41.5	$95.6	($5.4)	($0.0)	$90.2
Apr	$48.6	($4.0)	$0.0	$44.6	$81.1	($2.4)	($0.0)	$78.7
May	$72.6	($4.3)	$0.0	$68.2	$79.3	($4.4)	($0.0)	$74.9
Jun	$84.8	($5.0)	$0.0	$79.7	$143.9	($10.2)	($0.0)	$133.7
Jul	$136.4	($6.7)	$0.0	$129.8	$204.2	($7.6)	($0.0)	$196.6
Aug	$103.8	($6.4)	$0.0	$97.4	$99.4	($3.6)	$0.0	$95.9
Sep	$62.9	($4.4)	$0.0	$58.5	$91.9	($5.0)	($0.0)	$86.8
Oct	$67.1	($4.2)	$0.0	$63.0				
Nov	$59.3	($2.5)	($0.0)	$56.8				
Dec	$106.5	($5.8)	($0.0)	$100.7				
Total	$978.2	($62.6)	$0.0	$915.6	$1,149.5	($53.9)	($0.0)	$1,095.5

Figure 11-13 shows PJM monthly marginal loss costs for January 2008 through September 2025.

Figure 11-13 Monthly marginal loss cost (Dollars (Millions)): January 2008 through September 2025

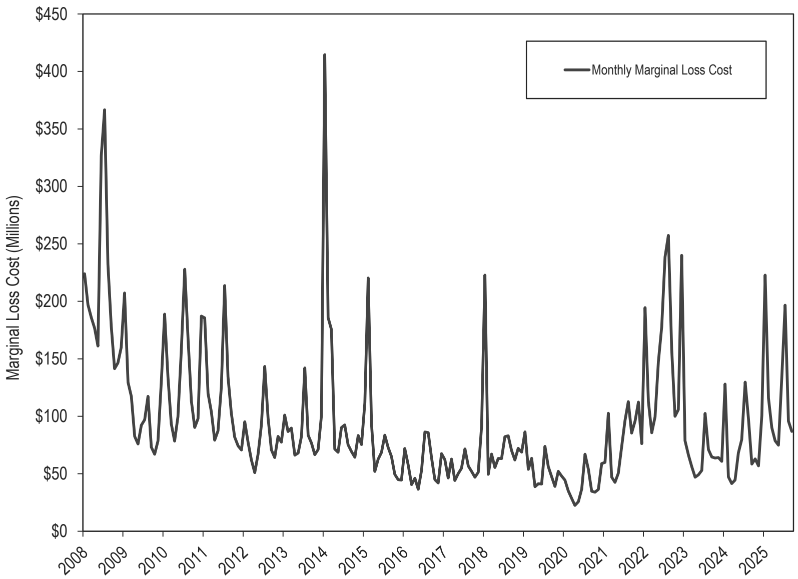


Table 11-43 shows the monthly total loss charges for each virtual transaction type for January 2024 through September 2025. In the first nine months of 2025, 90.7 percent of the total credits to virtuals went to UTCs, compared to 72.6 percent in the first nine months of 2024.

Table 11-43 Monthly loss charges by virtual transaction type (Dollars (Millions)): January 2024 through September 2025

		Marginal Loss Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2024	Jan	($0.5)	$0.5	($0.1)	$3.2	($3.6)	($0.4)	$9.0	($9.5)	($0.5)	($0.9)
	Feb	($0.7)	$0.7	$0.0	$2.0	($2.5)	($0.5)	$4.0	($4.9)	($0.8)	($1.3)
	Mar	($0.5)	$0.5	($0.0)	$2.5	($2.7)	($0.2)	$4.6	($5.1)	($0.5)	($0.7)
	Apr	($0.7)	$0.8	$0.1	$3.8	($3.5)	$0.3	$4.3	($4.2)	$0.2	$0.6
	May	($0.3)	$0.5	$0.2	$4.0	($4.2)	($0.2)	$4.7	($5.1)	($0.3)	($0.4)
	Jun	($0.6)	$1.0	$0.4	$2.5	($2.9)	($0.5)	$4.8	($5.1)	($0.3)	($0.4)
	Jul	$0.2	$0.9	$1.1	$3.1	($3.9)	($0.8)	$5.6	($5.8)	($0.2)	$0.0
	Aug	($0.2)	$0.7	$0.5	$2.3	($2.5)	($0.1)	$4.1	($4.6)	($0.5)	($0.1)
	Sep	($0.7)	$0.6	($0.0)	$1.6	($1.5)	$0.1	$2.9	($3.6)	($0.7)	($0.6)
	Oct	($0.6)	$0.8	$0.2	$3.4	($3.0)	$0.4	$4.0	($4.0)	($0.0)	$0.5
	Nov	($0.7)	$0.6	($0.0)	$2.9	($3.0)	($0.1)	$2.5	($2.8)	($0.3)	($0.4)
	Dec	$0.3	$0.2	$0.5	$4.2	($4.7)	($0.5)	$5.4	($5.5)	($0.0)	($0.1)
	Total	($5.1)	$7.8	$2.7	$35.5	($38.0)	($2.5)	$56.0	($60.1)	($4.1)	($3.9)
2025	Jan	($0.1)	$1.1	$1.0	$6.3	($7.6)	($1.3)	$9.4	($9.9)	($0.5)	($0.8)
	Feb	($0.4)	$0.4	($0.0)	$3.6	($4.8)	($1.1)	$5.5	($7.0)	($1.6)	($2.7)
	Mar	($0.4)	$0.8	$0.3	$5.1	($5.7)	($0.5)	$4.5	($4.9)	($0.5)	($0.7)
	Apr	($0.8)	$0.8	($0.0)	$4.5	($4.5)	($0.0)	$3.3	($3.6)	($0.3)	($0.3)
	May	$0.2	$0.1	$0.3	$3.4	($3.5)	($0.1)	$4.4	($3.9)	$0.4	$0.6
	Jun	($0.4)	$1.2	$0.8	$2.7	($3.7)	($1.0)	$7.5	($9.3)	($1.7)	($1.9)
	Jul	($2.2)	$2.7	$0.5	$3.7	($3.7)	($0.0)	$6.2	($7.2)	($1.0)	($0.5)
	Aug	($1.5)	$1.6	$0.2	$2.1	($2.0)	$0.1	$3.2	($3.9)	($0.7)	($0.5)
	Sep	($1.0)	$1.2	$0.3	$2.5	($2.5)	$0.0	$4.5	($5.3)	($0.7)	($0.5)
	Total	($6.6)	$10.0	$3.3	$33.9	($38.0)	($4.0)	$48.4	($55.0)	($6.6)	($7.3)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs (which are negative), the total marginal loss costs (which are positive) and net residual market adjustments (which can be net positive or negative). The total system energy costs are equal to the net implicit energy charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit load MLMP charges less implicit generation MLMP credits) plus net explicit loss charges plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more injection credits than withdrawal charges in every hour. The greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). Total system energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-44 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for January through September, 2008 through 2025. The total marginal loss surplus increased by $146.7 million or 56.8 percent in the first nine months of 2025 from the first nine months of 2024.

Table 11-44 Marginal loss surplus (Dollars (Millions)): January through September, 2008 through 2025[38]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustments			
(Jan - Sep)	System Energy Cost	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Marginal Loss Surplus
2008	($976.0)	$2,048.9	$0.0	$0.0	$0.0	$1,073.0
2009	($484.6)	$992.4	($0.0)	($0.4)	($0.1)	$508.3
2010	($618.6)	$1,259.3	$0.0	($0.6)	($0.1)	$641.5
2011	($651.3)	$1,152.6	$0.1	$1.3	($0.0)	$500.1
2012	($442.6)	$757.6	$0.1	($0.7)	$0.0	$315.7
2013	($527.2)	$797.0	$0.0	$1.7	$0.0	$268.0
2014	($833.9)	$1,243.1	($0.0)	$5.1	$0.1	$404.1
2015	($536.5)	$829.8	($0.3)	$4.7	($0.1)	$288.3
2016	($358.3)	$541.9	$0.0	$2.8	($0.2)	$181.0
2017	($344.0)	$501.0	$0.0	$0.7	($0.1)	$156.5
2018	($498.7)	$757.0	($0.0)	$1.9	($0.1)	$256.4
2019	($339.3)	$502.7	($0.0)	$1.3	($0.1)	$162.1
2020	($234.0)	$349.2	($0.0)	$1.1	($0.1)	$114.2
2021	($430.7)	$670.2	($0.0)	$2.5	($0.1)	$237.0
2022	($979.1)	$1,472.0	($0.0)	$5.6	($0.2)	$487.6
2023	($384.6)	$588.5	($0.0)	$1.3	($0.2)	$202.7
2024	($434.8)	$695.2	($0.0)	$2.1	($0.2)	$258.5
2025	($688.2)	$1,095.5	$0.0	$2.2	$0.0	$405.2

38 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

System Energy Costs

Energy Accounting

The system energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The system energy cost is based on the day-ahead and real-time energy components of LMP. Total system energy costs, analogous to total congestion costs or total loss costs, are equal to the withdrawal energy charges minus injection energy credits, in both the day-ahead energy market and the balancing energy market, plus net inadvertent energy charges. Total system energy costs can be more accurately thought of as net system energy costs. Due to line losses associated with moving energy from generation to load, more energy is injected by generation than is withdrawn by load. Total system energy charges are negative because there are, due to losses, more generation MW being paid SMP (energy component of price) than load MW paying SMP (the energy component of price).

Total System Energy Costs

The total system energy cost for the first nine months of 2025 was -$688.2 million, which was comprised of implicit withdrawal energy charges of $45,181.2 million, implicit injection energy credits of $45,863.1 million, explicit energy charges of $0.0 million and inadvertent energy charges of -$6.2 million. The monthly system energy costs for the first nine months of 2025 ranged from -$137.8 million in January to -$46.4 million in May. Table 11-45 shows total system energy costs and total PJM billing, for January through September, 2008 through 2025.

Table 11-45 Total system energy costs (Dollars (Millions)): January through September, 2008 through 2025[39 40]

(Jan - Sep)	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($976)	NA	$26,979	(3.6%)
2009	($485)	(50.3%)	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($527)	19.1%	$25,153	(2.1%)
2014	($834)	58.2%	$40,770	(2.0%)
2015	($537)	(35.7%)	$33,710	(1.6%)
2016	($358)	(33.2%)	$29,490	(1.2%)
2017	($344)	(4.0%)	$29,510	(1.2%)
2018	($499)	45.0%	$37,950	(1.3%)
2019	($339)	(32.0%)	$31,850	(1.1%)
2020	($234)	(31.0%)	$27,070	(0.9%)
2021	($431)	84.0%	$37,520	(1.1%)
2022	($979)	127.3%	$66,110	(1.5%)
2023	($385)	(60.7%)	$36,380	(1.1%)
2024	($435)	13.1%	$39,070	(1.1%)
2025	($688)	58.3%	$57,770	(1.2%)

System energy costs for January through September, 2008 through 2025 are shown in Table 11-46 and Table 11-47. Table 11-46 shows PJM system energy costs by accounting category and Table 11-47 shows PJM system energy costs by market category.

39 The system energy costs include net inadvertent charges.
40 In Table 11-45, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the MMU has modified the Total PJM Billing calculation to better reflect historical PJM total billing through the PJM settlement process.

Table 11-46 Total system energy costs by accounting category (Dollars (Millions)): January through September, 2008 through 2025

	System Energy Costs (Millions)				
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$91,391.9	$92,368.9	$0.0	$1.0	($976.0)
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.8	$33,279.9	$0.0	($4.2)	($527.2)
2014	$50,415.3	$51,245.6	$0.0	($3.6)	($833.9)
2015	$33,772.7	$34,311.9	$0.0	$2.6	($536.5)
2016	$25,858.3	$26,213.7	$0.0	($2.9)	($358.3)
2017	$26,082.1	$26,430.6	$0.0	$4.5	($344.0)
2018	$33,871.7	$34,376.1	$0.0	$5.7	($498.7)
2019	$23,696.4	$24,035.9	$0.0	$0.2	($339.3)
2020	$17,364.8	$17,600.7	$0.0	$1.9	($234.0)
2021	$28,853.8	$29,288.0	$0.0	$3.5	($430.7)
2022	$64,425.9	$65,400.0	$0.0	($5.0)	($979.1)
2023	$26,456.4	$26,844.2	$0.0	$3.2	($384.6)
2024	$29,702.8	$30,147.1	$0.0	$9.4	($434.8)
2025	$45,181.2	$45,863.1	$0.0	($6.2)	($688.2)

Table 11-47 Total system energy costs by market (Dollars (Millions)): January through September, 2008 through 2025

	System Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$67,568.7	$68,653.8	$0.0	($1,085.1)	$23,823.2	$23,715.1	$0.0	$108.1	$1.0	($976.0)
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,797.0	$33,398.3	$0.0	($601.3)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.2)
2014	$50,428.5	$51,603.0	$0.0	($1,174.5)	($13.2)	($357.4)	$0.0	$344.2	($3.6)	($833.9)
2015	$33,910.7	$34,549.7	$0.0	($639.0)	($138.0)	($237.8)	$0.0	$99.8	$2.6	($536.5)
2016	$25,986.4	$26,469.9	$0.0	($483.5)	($128.1)	($256.2)	$0.0	$128.1	($2.9)	($358.3)
2017	$26,360.1	$26,844.5	$0.0	($484.4)	($278.0)	($413.9)	$0.0	$135.9	$4.5	($344.0)
2018	$33,957.1	$34,508.6	$0.0	($551.4)	($85.4)	($132.5)	$0.0	$47.1	$5.7	($498.7)
2019	$24,004.0	$24,411.6	$0.0	($407.6)	($307.7)	($375.7)	$0.0	$68.0	$0.2	($339.3)
2020	$17,564.2	$17,867.8	$0.0	($303.6)	($199.4)	($267.1)	$0.0	$67.7	$1.9	($234.0)
2021	$28,994.9	$29,470.3	$0.0	($475.4)	($141.2)	($182.4)	$0.0	$41.2	$3.5	($430.7)
2022	$64,959.1	$66,075.9	$0.0	($1,116.7)	($533.3)	($675.9)	$0.0	$142.6	($5.0)	($979.1)
2023	$26,750.4	$27,264.3	$0.0	($513.9)	($294.0)	($420.1)	$0.0	$126.1	$3.2	($384.6)
2024	$30,182.6	$30,705.5	$0.0	($522.9)	($479.8)	($558.5)	$0.0	$78.7	$9.4	($434.8)
2025	$45,379.8	$46,158.3	$0.0	($778.5)	($198.6)	($295.2)	$0.0	$96.5	($6.2)	($688.2)

Table 11-48 and Table 11-49 show the total system energy costs for each transaction type in the first nine months of 2025 and 2024. In the first nine months of 2025, generation was paid $32,614.9 million and demand paid $30,639.0 million in net energy payment. In the first nine months of 2024, generation was paid $21,386.7 million and demand paid $20,183.0 million in net energy payment.

Table 11-48 Total system energy costs by transaction type (Dollars (Millions)): January through September, 2025

System Energy Costs (Millions)									
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$1,779.9	$0.0	$0.0	$1,779.9	($1,805.7)	$0.0	$0.0	($1,805.7)	($25.9)
Demand	$30,100.6	$0.0	$0.0	$30,100.6	$538.4	$0.0	$0.0	$538.4	$30,639.0
Demand Response	($29.3)	$0.0	$0.0	($29.3)	$28.6	$0.0	$0.0	$28.6	($0.7)
Export	$1,351.6	$0.0	$0.0	$1,351.6	$584.4	$0.0	$0.0	$584.4	$1,935.9
Generation	$0.0	$32,270.5	$0.0	($32,270.5)	$0.0	$344.4	$0.0	($344.4)	($32,614.9)
Import	$0.0	$82.5	$0.0	($82.5)	$0.0	$548.1	$0.0	($548.1)	($630.6)
INC	$0.0	$1,628.2	$0.0	($1,628.2)	$0.0	($1,643.3)	$0.0	$1,643.3	$15.1
Internal Bilateral	$12,170.2	$12,170.2	$0.0	$0.0	$436.1	$436.1	$0.0	$0.0	$0.0
Wheel In	$0.0	$6.9	$0.0	($6.9)	$0.0	$19.6	$0.0	($19.6)	($26.5)
Wheel Out	$6.9	$0.0	$0.0	$6.9	$19.6	$0.0	$0.0	$19.6	$26.5
Total	$45,379.8	$46,158.3	$0.0	($778.5)	($198.6)	($295.2)	$0.0	$96.5	($681.9)

Table 11-49 Total system energy costs by transaction type by (Dollars (Millions)): January through September, 2024

System Energy Costs (Millions)									
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$1,222.0	$0.0	$0.0	$1,222.0	($1,248.2)	$0.0	$0.0	($1,248.2)	($26.3)
Demand	$19,875.4	$0.0	$0.0	$19,875.4	$307.6	$0.0	$0.0	$307.6	$20,183.0
Demand Response	($8.8)	$0.0	$0.0	($8.8)	$8.6	$0.0	$0.0	$8.6	($0.3)
Export	$786.9	$0.0	$0.0	$786.9	$343.3	$0.0	$0.0	$343.3	$1,130.2
Generation	$0.0	$21,329.1	$0.0	($21,329.1)	$0.0	$57.5	$0.0	($57.5)	($21,386.7)
Import	$0.0	$64.2	$0.0	($64.2)	$0.0	$304.3	$0.0	($304.3)	($368.4)
INC	$0.0	$1,005.0	$0.0	($1,005.0)	$0.0	($1,029.2)	$0.0	$1,029.2	$24.2
Internal Bilateral	$8,302.1	$8,302.1	$0.0	($0.0)	$82.4	$82.4	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$5.0	$0.0	($5.0)	$0.0	$26.6	$0.0	($26.6)	($31.6)
Wheel Out	$5.0	$0.0	$0.0	$5.0	$26.6	$0.0	$0.0	$26.6	$31.6
Total	$30,182.6	$30,705.5	$0.0	($522.9)	($479.8)	($558.5)	$0.0	$78.7	($444.3)

Table 11-50 compares the total system energy costs for each transaction type between the dispatch run and the pricing run in the first nine months of 2025. The system energy charges to demand increased $90.3 million, and the energy credits to generation decreased $64.4 million from the dispatch run to the pricing run. The energy charges to DEC decreased $152.2 million, the energy credits to INC increased $131.1 million from the dispatch run to the pricing run.

Table 11-50 Total system energy costs by dispatch and pricing run (Dollars (Millions)): January through September, 2025

System Energy Costs (Millions)									
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$1,777.6	($1,651.3)	$126.3	$1,779.9	($1,805.7)	($25.9)	$2.2	($154.4)	($152.2)
Demand	$30,059.8	$488.9	$30,548.8	$30,100.6	$538.4	$30,639.0	$40.8	$49.5	$90.3
Demand Response	($29.3)	$25.9	($3.3)	($29.3)	$28.6	($0.7)	($0.0)	$2.7	$2.7
Export	$1,349.8	$542.3	$1,892.1	$1,351.6	$584.4	$1,935.9	$1.8	$42.1	$43.8
Generation	($32,226.4)	($324.1)	($32,550.5)	($32,270.5)	($344.4)	($32,614.9)	($44.1)	($20.3)	($64.4)
Import	($82.5)	($501.1)	($583.6)	($82.5)	($548.1)	($630.6)	($0.0)	($47.0)	($47.0)
INC	($1,626.6)	$1,510.6	($116.0)	($1,628.2)	$1,643.3	$15.1	($1.5)	$132.6	$131.1
Internal Bilateral	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Wheel In	($6.9)	($17.9)	($24.7)	($6.9)	($19.6)	($26.5)	($0.0)	($1.7)	($1.7)
Wheel Out	$6.9	$17.9	$24.7	$6.9	$19.6	$26.5	$0.0	$1.7	$1.7
Total	($777.5)	$91.2	($686.2)	($778.5)	$96.5	($681.9)	($1.0)	$5.3	$4.3

Monthly System Energy Costs

Table 11-51 shows a monthly summary of system energy costs by market type for January 2024 through September 2025. Total balancing system energy costs in the first nine months of 2025 decreased in every month compared to the first nine months of 2024. Monthly total system energy costs in the first nine months of 2025 ranged from -$137.8 million in January to -$46.4 million in May.

Table 11-51 Monthly system energy costs (Dollars (Millions)): January 2024 through September 2025

System Energy Costs (Millions)								
	2024				2025			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($99.5)	$12.5	$0.7	($86.3)	($153.9)	$16.7	($0.6)	($137.8)
Feb	($39.3)	$7.7	$0.0	($31.7)	($85.3)	$9.8	($0.8)	($76.2)
Mar	($36.8)	$9.3	($0.1)	($27.6)	($68.3)	$12.4	($1.0)	($56.9)
Apr	($36.3)	$7.2	$0.3	($28.8)	($55.5)	$7.0	($1.2)	($49.7)
May	($51.6)	$9.0	$1.0	($41.6)	($56.4)	$11.5	($1.5)	($46.4)
Jun	($58.1)	$7.2	$2.0	($49.0)	($95.5)	$10.0	($0.4)	($86.0)
Jul	($88.1)	$9.9	$3.3	($74.9)	($133.5)	$9.7	($0.4)	($124.2)
Aug	($68.7)	$9.6	$1.5	($57.6)	($65.6)	$6.9	$0.7	($58.0)
Sep	($44.4)	$6.3	$0.7	($37.4)	($64.4)	$12.4	($1.0)	($53.0)
Oct	($47.2)	$7.5	$0.3	($39.4)				
Nov	($42.5)	$5.5	($0.1)	($37.1)				
Dec	($73.3)	$10.9	($0.4)	($62.9)				
Total	($685.9)	$102.6	$9.2	($574.1)	($778.5)	$96.5	($6.2)	($688.2)

Figure 11-14 shows PJM monthly system energy costs for January 2008 through September 2025. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP (SMP) is the same for every bus in the market in every hour, the net energy bill is always negative (ignoring net interchange): (SMP x withdrawals + SMP x injections) < 0. Assuming power balance is maintained in the presence of losses, the greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). With higher load levels, there are generally higher SMPs and more negative total energy charges.

Figure 11-14 Monthly system energy costs (Millions): January 2008 through September 2025

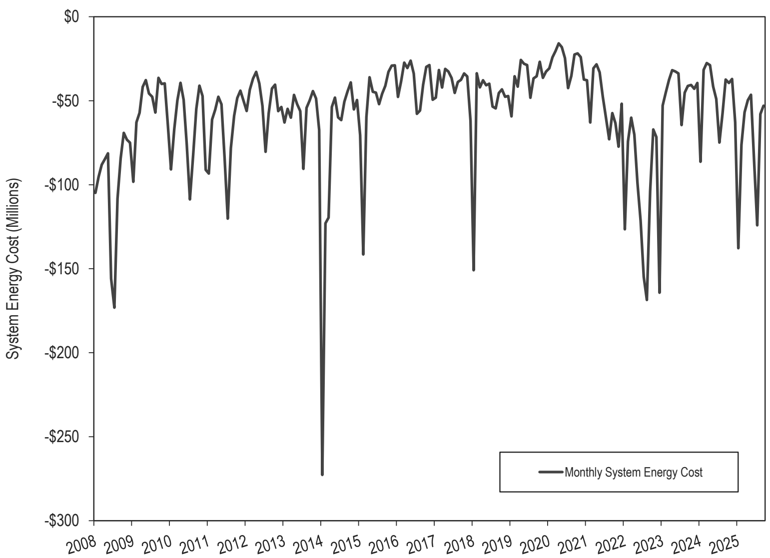


Table 11-52 shows the monthly total system energy costs for each virtual transaction type in the first nine months of 2025 and 2024. In the first nine months of 2025, DECs paid $1,779.9 million in energy charges compared to $1,222.0 million in the first nine months of 2024 in the day-ahead market, were paid $1,805.7 million in energy credits compared to $1,248.2 million in the first nine months of 2024 in the balancing energy market and paid $25.9 million in total energy charges compared to $26.3 million in total energy credits in the first nine months of 2024. In the first nine months of 2025, INCs were paid $1,628.2 million in energy credits compared to $1,005.0 million in the first nine months of 2024 in the day-ahead market, paid $1,643.3 million in energy charges compared to $1,029.2 million in the first nine months of 2024 in the balancing market and were paid $10.7 million in total energy credits compared to $2.1 million in total energy charges in the first nine months of 2024. The system energy costs are zero for UTCs because the system energy costs for UTCs equal the difference in the energy component between source and sink and the energy component is the same at all buses.

Table 11-52 Monthly energy charges by virtual transaction type (Dollars (Millions)): January 2024 through September 2025

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2024	Jan	$185.4	($164.2)	$21.2	($151.0)	$135.1	($15.9)	$5.3
	Feb	$85.7	($90.4)	($4.7)	($90.6)	$94.5	$3.9	($0.9)
	Mar	$96.9	($102.4)	($5.5)	($95.4)	$99.5	$4.0	($1.4)
	Apr	$100.5	($101.1)	($0.6)	($110.1)	$110.9	$0.8	$0.2
	May	$131.5	($144.1)	($12.6)	($136.9)	$151.1	$14.2	$1.7
	Jun	$132.9	($135.7)	($2.8)	($104.8)	$107.1	$2.3	($0.4)
	Jul	$182.2	($197.0)	($14.9)	($133.9)	$145.2	$11.3	($3.6)
	Aug	$176.2	($179.7)	($3.5)	($102.0)	$102.9	$0.9	($2.6)
	Sep	$130.7	($133.6)	($2.9)	($80.3)	$82.9	$2.6	($0.3)
	Oct	$115.9	($111.0)	$4.9	($124.2)	$118.0	($6.2)	($1.3)
	Nov	$102.4	($95.9)	$6.5	($112.2)	$105.7	($6.5)	($0.0)
	Dec	$166.0	($154.8)	$11.2	($152.4)	$145.6	($6.8)	$4.4
	Total	$1,606.3	($1,609.9)	($3.6)	($1,393.9)	$1,398.5	$4.7	$1.1
2025	Jan	$232.3	($228.2)	$4.1	($269.2)	$261.9	($7.3)	($3.2)
	Feb	$167.5	($168.2)	($0.7)	($192.3)	$191.8	($0.5)	($1.2)
	Mar	$159.2	($164.8)	($5.6)	($181.7)	$188.6	$6.9	$1.3
	Apr	$144.2	($146.2)	($2.0)	($193.9)	$196.4	$2.5	$0.5
	May	$143.6	($138.3)	$5.3	($141.2)	$139.1	($2.1)	$3.2
	Jun	$225.4	($273.0)	($47.6)	($148.9)	$182.0	$33.1	($14.5)
	Jul	$310.6	($281.0)	$29.7	($225.8)	$200.9	($24.9)	$4.7
	Aug	$192.0	($193.1)	($1.1)	($134.2)	$134.5	$0.3	($0.8)
	Sep	$205.1	($212.9)	($7.8)	($141.0)	$148.1	$7.1	($0.7)
	Total	$1,779.9	($1,805.7)	($25.9)	($1,628.2)	$1,643.3	$15.1	($10.7)

Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2025, PJM had a total installed capacity of 200,952.5 MW, of which 38,366.4 MW (19.1 percent) are coal fired steam units, 57,064.2 MW (28.4 percent) are combined cycle units and 33,452.6 MW (16.6 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 200,952.5 MW of installed capacity, 72,221.3 MW (35.9 percent) are from units older than 40 years, of which 30,814.3 MW (42.7 percent) are coal fired steam units, 255.0 MW (0.4 percent) are combined cycle units and 25,550.6 MW (35.4 percent) are nuclear units.

Generation Retirements[2]

- As of September 30, 2025, there were 64,079.0 MW of generation that have been, or are planned to be, retired between 2011 and 2030, of which 46,526.8 MW (72.6 percent) are coal fired steam units.
- In the first nine months of 2025, 981.8 MW of generation retired. The largest generator that retired in the first nine months of 2025 was the 410.0 MW Indian River 4 coal fired steam unit located in the DPL Zone. Of the 981.8 MW of generation that retired in the first nine months of 2025, 410.0 MW (41.8 percent) were located in the DPL Zone.
- As of September 30, 2025, there were 8,351.9 MW of generation that have requested retirement after September 30, 2025, of which 2,620.0 MW (31.4 percent) are located in the AEP Zone. Of the generation requesting retirement in the AEP Zone, 2,620.0 MW (100.0 percent) are coal fired steam units.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2025) <https://www.pjm.com/planning/service-requests/gen-deactivations>.

Generation Queue

New Service Requests Serial Process[3]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[4] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out serial processing method.[5] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The transition to the new queue process began on July 10, 2023.
- There were 8,190 generation request projects submitted in the new service request serial process queue from 1997 until the implementation of the new cycle process on July 10, 2023. As a result of the transition to the new services cycle process, 312 projects were moved to transition cycle 1 (TC1). There were 1,347 projects eligible to resubmit for evaluation in transition cycle 2 (TC2). Of those 1,347 eligible projects, 550 projects resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects did not resubmit, and were withdrawn from the queue. There were 1,070 projects initially entered into the AH2 queue and beyond. Those 1,070 projects are now considered invalid and have been removed from the queue. As a result of the transition to the cycle process, the 8,190 projects in the serial process queue have been reduced to 5,461 projects. Projects that will be evaluated in TC1 and TC2, and those projects no longer eligible to be evaluated in the serial process have been removed from the new service requests serial process metrics. New service requests cycle process metrics are reported separately from the serial process metrics.
- As of September 30, 2025, a total of 43,634.4 MW, on an energy basis, were in generation request serial service queues in the status of active,

3 See PJM. Planning. "Serial Service Request Status," (Accessed on September 30, 2025) <https://www.pjm.com/planning/service-requests/serial-service-request-status>.
4 See 181 FERC ¶ 61,162 (2022).
5 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

under construction or suspended.[6] Based on historical completion rates, 23,288.8 MW (53.4 percent), on an energy basis, of new generation in the queue are expected to go into service. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.

- Of the 4,158.8 MW, on an energy basis, of combined cycle projects in the serial queue, 2,958.5 MW (71.1 percent) are expected to go in service based on historical completion rates as of September 30, 2025.
- Of the 3,426.1 MW, on an energy basis, of battery projects in the serial queue, only 931.2 MW (27.2 percent) are expected to go in service based on historical completion rates as of September 30, 2025.
- Of the 34,851.8 MW, on an energy basis, of renewable projects in the serial queue, 18,564.5 MW (53.3 percent) are expected to go in service based on historical completion rates as of September 30, 2025.
- Of the 3,949.1 MW, on a capacity basis that requested CIRs, of combined cycle projects requested in the generation serial queues in the status of active, under construction or suspended, 2,777.1 MW (70.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction,[7] the 3,949.1 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,055.1 MW of capacity (52.0 percent of the total requested capacity).[8]
- Of the 2,232.3 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation serial queues in the status of active, under construction or suspended, 161.5 MW (7.2 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 2,232.3 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 93.7 MW of capacity (4.2 percent of the total requested capacity).
- Of the 18,186.8 MW, on a capacity basis that requested CIRs, of renewable projects requested in the serial generation queues in the status of active, under construction or suspended, 9,797.0 MW (53.9 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 18,186.8 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 965.8 MW of capacity (5.3 percent of the total requested capacity).
- As of September 30, 2025, 25,603.7 MW of capacity requests (requested CIRs) were in the generation serial queues in the status of active, under construction or suspended. Based on historical completion rates, 13,565.8 MW (53.0 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 25,603.7 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 3,631.5 MW of capacity (14.2 percent of the total requested capacity).
- As of September 30, 2025, 5,461 projects, representing 609,132.6 MW, have entered the serial queue process since its inception. Of those, 1,267 projects, representing 93,774.7 MW (15.4 percent of the MW), went into service. Of the projects that entered the serial queue process, 3,734 projects, representing 471,723.5 MW (77.4 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed, by taking up queue positions, increasing interconnection costs and creating uncertainty.
- In the first nine months of 2025, 2,117.1 MW from the serial queue went into service. Of the 2,117.1 MW that went in service, 1,883.2 MW (89.0 percent) were solar units, 150.0 MW (7.1 percent) were solar + storage

6 Unless otherwise noted, the queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
7 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2027/2028 Base Residual Auction*, PJM Interconnection L.L.C. (August 1, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf>.
8 Unless otherwise noted, the ELCC derate adjusted MW are calculated using the 2027/2028 Base Residual Auction ELCC factors. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

units, 54.9 MW (2.6 percent) were wind units and 29.0 MW (1.3 percent) were coal fired steam units.

- The number of serial queue entries increased during the past several years, primarily renewable projects. Of the 2,809 projects that entered the serial queue from January 1, 2015, through July 10, 2023, 2,062 projects (73.4 percent) were renewable. Of the 690 projects that entered the serial queue in 2020, 545 projects (79.0 percent) were renewable. Renewable projects make up 85.9 percent of all projects in the serial queue and account for 79.9 percent of the nameplate MW currently active, suspended or under construction in the serial queue as of September 30, 2025.
- On September 30, 2025, 31,841.9 MW, on an energy basis, were in generation request serial queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Of the 31,841.9 MW, 12,683.3 MW (39.8 percent) had not begun construction, 9,873.5 MW (31.0 percent) had begun construction, but are now suspended, and 9,285.2 MW (29.2 percent) are currently under construction. Reaching the final milestone required prior to construction does not mean a project will immediately begin construction or even that it necessarily will ever begin construction.

New Service Requests Cycle Process[9]

Transition Cycle 1 (TC1)

- Transition cycle 1 (TC1) is comprised of 312 proposed generation projects. Those projects make up 40,650.2 MW. On September 30, 2025, all projects in TC1 were either in the status of active or were withdrawn from the cycle. Of the 40,650.2 MW in TC1, 17,873.8 MW (44.0 percent) were active and 22,776.3 MW (56.0 percent) were withdrawn.
- On September 30, 2025, there were 17,873.8 MW, on an energy basis, of which 8,854.3 MW are on a capacity basis that requested CIRs, in TC1 in the status of active.
- Of the 8,854.3 MW, on a capacity basis that requested CIRs in TC1 in the status of active, 2,152.8 MW (24.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 5,082.0 MW, on a capacity basis that requested CIRs, of solar projects requested in TC1 in the status of active, 406.6 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 1,565.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC1 in the status of active, 907.9 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 6,720.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC1 in the status of active, 897.9 MW (13.4 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Transition Cycle 2 (TC2) and Reliability Resource Initiative (RRI)

- On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[10] On February 11, 2025, the Commission approved the RRI tariff modifications.[11] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period.
- PJM received 97 applications (28.6 GW) of RRI projects during the RRI application window. Of these projects, 48 involve uprates, in which existing resources are modified to increase the economic maximum generation capability, and 49 propose building new generation. PJM reviewed the submitted RRI projects using the Commission approved scoring criteria, and approved 51 projects (11,577.4 MW).[12] On September 30, 2025, all RRI projects were either in the status of active or withdrawn from the cycle.

9 See PJM. Planning. "Cycle Service Request Status," (Accessed on September 30, 2025) <https://www.pjm.com/planning/m/cycle-service-request-status>.

10 See *PJM Interconnection L.L.C.* Docket No. ER25-712 (December 13, 2024).

11 190 FERC ¶ 61,084 (February 11, 2025).

12 The RRI proposal was to select the top 50 projects using the approved scoring criteria. The implemented scoring criteria resulted in a tie for the 50th project. This resulted in PJM selecting 51 projects as part of the RRI process.

Of the 11,577.4 MW of approved RRI projects, 10,938.4 MW (94.5 percent) were active and 639.0 MW (5.5 percent) were withdrawn.

- Transition cycle 2 (TC2) is comprised of 647 proposed generation projects. TC2 includes 550 projects submitted during the TC2 window, and 97 projects submitted through the RRI window. Those projects make up 78,329.4 MW. On September 30, 2025, all projects in TC2 were either in the status of active or were withdrawn from the cycle. Of the 78,329.4 MW in TC2, 45,977.6 MW (58.7 percent) were active and 32,351.8 MW (41.3 percent) were withdrawn.
- On September 30, 2025, there were 45,977.6 MW, on an energy basis, of which 32,120.8 MW are on a capacity basis that requested CIRs, in TC2 in the status of active.
- Of the 32,120.8 MW, on a capacity basis that requested CIRs in TC2 in the status of active, 14,167.2 MW (44.1 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 10,051.8 MW, on a capacity basis that requested CIRs, of solar projects requested in TC2 in the status of active, 804.1 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 7,400.0 MW, on a capacity basis that requested CIRs, of battery projects requested in TC2 in the status of active, 4,292.0 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 13,167.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC2 in the status of active, 1,146.4 MW (8.7 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Cycle Process Totals[13]

- On September 30, 2025, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 118,979.6 MW. On September 30, 2025, all projects in the cycle process queues were either in the status of active or were withdrawn. Of the 118,979.6 MW in the cycle process queues, 63,851.5 MW (53.7 percent) were active and 55,128.1 MW (46.3 percent) were withdrawn.
- On September 30, 2025, there were 63,851.5 MW, on an energy basis, of which 40,975.1 MW are on a capacity basis that requested CIRs, in cycle process queues in the status of active.
- Of the 40,975.1 MW, on a capacity basis that requested CIRs in the cycle process queues in the status of active, 16,320.0 MW (39.8 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 15,133.8 MW, on a capacity basis that requested CIRs, of solar projects requested in cycle process queues in the status of active, 1,210.7 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 8,965.3 MW, on a capacity basis that requested CIRs, of battery projects requested in cycle process queues in the status of active or under construction, 5,199.9 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 19,887.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in cycle process queues in the status of active or under construction, 2,044.2 MW (10.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

13 As of September 30, 2025, the cycle process totals include those projects included in TC1 and TC2.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. If done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis would include the total net change in production costs and would not include congestion. In addition, PJM's benefit/cost analysis includes only the decreases in costs to load and ignores the increases in costs to load associated with market efficiency projects.
- Through September 30, 2025, PJM has completed five market efficiency cycles under Order No. 1000.[14] PJM delayed the opening of the 2022/2023 Long-Term Window until the reliability violations for the 2022 Window 3 were addressed. In January 2024, PJM completed updating the 2022/2023 market efficiency base case to include the solution selected from the 2022 Window 3. No flowgates experienced historical congestion that required an open window. PJM will continue to analyze the congestion patterns as part of the 2024/2025 Market Efficiency cycle. In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. PJM posted an updated 2024/2025 base case in July 2024, and requested stakeholder feedback by August 31, 2024. As of June 5, 2025, PJM completed its production cost simulations for the 2025 study year using existing topology and production cost simulations using the RTEP topology. As of June 5, 2025, PJM completed its production cost simulation of the 2029 study year with RTEP topology. The long term market efficiency window opened on April 11, 2025, and closed on June 10, 2025. The next step in the annual RTEP project acceleration process (RTEP market efficiency process) is to identify the specific RTEP reliability projects that reduce congestion costs in the simulation results.[15] The chosen projects will be presented in the fourth quarter of 2025.

14 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).
15 See PJM Operating Agreement, Section 1.5.7 (b) and (c).

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.
- The simultaneous use for joint projects of an incorrectly defined benefit/cost method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass a correctly defined benefit/cost test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

PJM MISO Interregional Transfer Capability Study (ITCS)

- PJM and MISO developed the Interregional Transfer Capability Study (ITCS) to help identify potential transmission projects that could incrementally improve the systems' ability to mitigate constraints, improve market efficiency, respond to extreme weather and increase interregional transfer capability.

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[16] Supplemental projects are exempt from competition.

- The average number of supplemental projects in each expected in service year increased by 1,110.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 242 for years 2008 through 2025 (post Order 890).[17]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build the project. Under the current approach, end of life projects are excluded from the RTEP process and exempt from competition.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews proposals to improve transmission reliability in PJM and between PJM and neighboring regions. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[18] In the first nine months of 2025, the PJM Board approved $7.9 billion in upgrades. As of September 30, 2025, the PJM Board has approved $58.0 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives, and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.

- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system, financed and built by market participants, that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2025, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When a reportable transmission facility needs to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[19]

- There were 11,918 transmission outage requests submitted in the first four months of the 2025/2026 planning period. Of the requested outages, 66.6 percent were planned for less than or equal to five days and 13.6 percent were planned for greater than 30 days. Of the requested outages, 31.0 percent were late according to the rules in PJM's Manual 3.

16 See PJM. "Transmission Construction Status," (Accessed on September 30, 2025) <https://www.pjm.com/planning/m/project-construction>.
17 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).
18 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.
19 See "PJM Manual 03: Transmission Operations," Rev. 68 (May 21, 2025).

Recommendations

Generation Retirements

- The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors or to exercise market power by requiring high payments for CIRs.[20] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. PJM does not update this data. (Priority: High. First reported 2023. Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: High. First reported 2024. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as an expedited process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[21] (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[22] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all changes in production costs but not congestion costs, including increased costs to load and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. The MMU also recommends that, if the market efficiency process is retained, market efficiency projects that fail to meet PJM benefit/cost criteria in a Schedule 6 annual reevaluation, prior to construction commencing or prior to state

20 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

21 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).

22 Ibid.

approval, be canceled and removed from further consideration. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to require competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[23]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[24]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and require competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to require competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax allocation method is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No

23 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

24 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)

- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the transmission facilities.[25] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Partially adopted.)
- The MMU recommends that all PJM transmission owners investigate the applicability and potential cost savings of Grid Enhancing Technology (GET) and that all PJM transmission owners implement cost effective GET, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2024. Status: Not adopted.)
- The MMU recommends that the implementation of Grid Enhancing Technology (GET) be opened to competition from third parties, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2024. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a definition of the economic and physical congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date, based on those options. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Conclusion

The goal of the PJM market design should be to enhance competition and to ensure that competition is the core element of all PJM markets. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. When generating units retire or load increases, there is no market mechanism in place that would require or even permit direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to require competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The MMU recognizes that the Commission has issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally

25 See *2015 State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Order No. 1000 removed the right of first refusal (ROFR) for transmission projects for incumbent transmission owners except for the case of supplemental projects. This created an incentive for incumbent transmission owners to designate projects as supplemental projects to avoid the Order No. 1000 competitive provisions. Two PJM states, Indiana and Michigan, have passed laws that provide ROFR to incumbent utilities/transmission owners.[26] [27]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented. All PJM Transmission Owners should be required to immediately adopt current dynamic line rating (DLR) methods for all transmission facilities, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC.

26 See IN Code § 8-1-38-9, effective 7/1/2023. Applies to transmission facilities approved for construction through an RTO planning process. Incumbent Transmission Owner must exercise within 90 days.

27 See MCL §460.593, effective 12/17/2021. Applies to regionally cost shared transmission lines included in a plan adopted by a recognized planning authority. Must be exercised by the incumbent (s) within 90 days after plan is adopted/approved.

Given the slow pace of adoption by Transmission Owners of Grid Enhancing Technologies (GETs), PJM and the Commission should introduce rules that would allow third parties to propose adding GETs to the transmission system, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The third parties would be compensated in the same way that TOs would be compensated for comparable investments.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

It would be antithetical to competition to permit transmission owners to own black start units under the backstop rules, to own batteries (storage as a transmission asset) or to permit transmission owners to build new generation, all under the antiquated cost of service regulation rules that were displaced by more efficient competitive markets. Such an approach would undermine competitive markets and require market projects built with investors' capital at risk to compete with subsidized resources.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to require competition to build the project. If there is no defined need for a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

Managing the generation queues is a complex process. The PJM queue evaluation process will be significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[28] [29] The new rules include significant modifications to the interconnection process designed to address some of the key underlying issues and significantly improve the efficiency of the process. These modifications include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation. The new process should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

While the changes in the queue process will clearly improve the process, the MMU's recommendations related to the queue process will remain until the new process is fully in place and it can be evaluated. The impact of the modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. The impact of these aspects of the revised interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. Initial results from the transition cycles have shown that developers are withdrawing their projects at the specified decision points, which is helping to remove speculative projects from the queue process sooner. Whether the new cycle process will result in enough new dispatchable and renewable generation to meet system needs cannot be determined until after a full cycle has been completed, projects go in service and completion rates can be evaluated. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs and whether transmission owners should perform interconnection studies.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

On January 31, 2025, PJM submitted revisions to the PJM Tariff to expedite the transfer of CIRs from deactivating generating resources to new replacement resources.[30] The Market Monitor filed opposing comments.[31] The Commission rejected the filing, finding (i) "that the lack of a maximum time limit for Commercial Operation Date extensions, which introduces the opportunity to delay commercial operation for an indefinite period of time, would result in a generator replacement process that does not promote the efficient interconnection of new resources;" and (ii) "because the unrestricted opportunity for a Replacement Generation Resource Project Developer to significantly delay commercial operation may result in CIRs and associated transmission capacity dedicated to accommodate the Replacement Generation Resource's operation going unused."[32] PJM has filed a new proposal for rule transferring CIRs to replacement resources which attempts to correct the deficiencies identified by FERC but continues to be flawed.[33]

The suggestion that generation owners should be permitted to avoid the queue process and directly transfer the generation CIRs to an affiliate or directly

28 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
29 See 181 FERC ¶ 61,162 (2022).
30 See PJM Interconnection, L.L.C., Docket No. ER25-1128 (January 31, 2025).
31 See Comments of the Independent Market Monitor for PJM, Docket No. ER25-1128-000 (February 21, 2025).
32 192 FERC ¶ 61,137 at PP 38–39 (2025).
33 *See PJM Interconnection, L.L.C.*, Docket No. ER26-403-000 (October 31, 2025).

sell the CIRs to an unaffiliated entity should be rejected.[34] [35] This proposed approach is about creating a process to maximize the value of existing CIRs to incumbent generators and not about facilitating the efficient replacement of retiring resources. In effect, this approach, if adopted by the large number of retiring units, would create a chaotic, bilateral private queue process that would create market power and facilitate the exercise of market power in the sale of CIRs by incumbent generators. In effect the proposed approach would replace a significant part of the recently redesigned PJM queue process. The proposed continuation of retention of CIRs by incumbent generators creates the potential for delays of up to a year and the proponents have proposed the option to request further delays. This approach would inappropriately delegate the authority from PJM to the incumbent generator to choose the new resource based on highest offer for CIRs rather than based on PJM defined system reliability needs. There would be no requirement to even be a capacity resource and there would be no requirement to offer the capacity into the capacity market. After the entire process, the contribution to PJM reliability could be zero. PJM's recently proposed expedited process for addressing reliability needs (RRI) is preferable and should be considered as the preferred alternative to the proposed approach from the Planning Committee stakeholder process.

The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. Rules should be developed to permit PJM to advance projects in the queue if they would resolve immediate reliability issues that result, for example, from unit retirements. The rules should be consistent with the flexibility included in the new queue process but add the option for PJM to expedite the interconnection and commercial operation of projects in the queue that would address identified reliability issues, consistent with the standing of the projects in the queue.

The PJM queue process should continue to define available and needed CIRs for all capacity queue projects. CIRs from retiring units should be made available to the next resource in the queue that can use them, on the retirement date of the retiring resource. Generation owners do not have property rights in CIRs. The value of CIRs is a result of the entire transmission system which has been paid for by customers and other generators. The value of CIRs is a result of the existence of a network and is not a result solely or even primarily of the investment that may or may not have been required in order to get CIRs. The cost of CIRs is part of project costs included in generation owners' investment decisions like any other project cost and subject to the same risk and reward structure. Open access to the transmission system by new resources should not be limited by claims to own the access rights by retiring units. In addition, the proposal to bypass the PJM interconnection process with a private, bilateral process ignores the fact that if the new resource is a renewable resource or a storage resource, the new resource does not have a capacity market must offer requirement. The PJM interconnection process could be bypassed, CIRs transferred and then the resource does not offer into the capacity market. In that case, scarce CIRs will be withheld by a generator who does not provide capacity and customers have to pay for an additional capacity resource instead.

The fundamental purpose of the queue process is to provide open access to the grid for supply resources. More specifically, the fundamental purpose of the queue process for capacity resources is to provide open access to the grid and to ensure that the energy from capacity resources is deliverable so that capacity resources can meet their must offer obligations in the energy market and provide reliable energy supply during all conditions. In order to ensure that open access, all capacity resources should be required to have a must offer obligation in the capacity market. If they do not, such resources are effectively withholding access to the grid from capacity resources that would take on a must offer obligation in the capacity market. The result creates market power for the resources with no must offer obligation, noncompetitively limits access

34 See PJM. "*Enhancing Capacity Interconnection Rights (CIR) Transfer Efficiency: Problem / Opportunity Statement*," <https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230731/20230731-item-08b---enhancing-capacity-interconnection-rights---cir---transfer-efficiency-problem-statement.ashx>.

35 On April 30, 2024, the CIR Transfer Efficiency issue was transferred from the Interconnection Process Subcommittee (IPS) to the Planning Committee (PC).

to the grid, increases capacity market prices above the competitive level, and creates uncertainty and unpredictable volatility in the capacity market.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current benefit/cost analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an incorrectly defined cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO transmission projects to PJM participants and in some cases approval of projects that do not pass a correctly defined benefit/cost test.

If it is retained, there are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. The current benefit/cost analysis explicitly and incorrectly ignores the increased costs to load in zones that results from an RTEP project when calculating the energy market benefits. All increases and decreases in costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the benefit/cost analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the benefit/cost analysis.

Recent proposals to use storage as a transmission asset (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. Storage is a market asset and should not be owned by transmission owners. PJM should not be evaluating SATA at all without a decision from FERC that SATA is allowable in PJM. At present it is not allowed.

A significant flaw in PJM's benefit/cost analysis is that projected benefits are based on load forecasts which are currently dominated by projected large data center loads that are not verified by PJM and cannot be verified by PJM. That creates a bias towards finding transmission projects beneficial despite the fact that data center loads are imposing transmission costs on other customers as a result.

There are currently no market incentives for transmission owners to plan, submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the day-ahead energy market and that have large and unnecessary impacts on the PJM energy market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear and expanded definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules. PJM Manual 38 currently defines congestion resulting from a transmission outage as an overload on transmission facilities rather than using the general economic definition of congestion resulting from out of merit generation to control constraints. PJM does not currently evaluate the economic impact of congestion when reviewing proposed transmission outages.[36]

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. PJM's analysis of expected congestion did not highlight the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion until after there were significant disruptions and congestion.

As an example of the complexities of defining the benefits of transmission investments, the reduction in congestion is frequently and incorrectly cited as a metric of benefits. Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. The correct metric is the total net change in production costs.

There is not a secular trend towards increasing congestion in PJM. Congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission to address a specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual transmission investment on future congestion. It is possible, for example, that congestion occurring during a period of a few days in the winter as a result of very high fuel prices, significantly increases the reported level of congestion for the entire year. This has occurred in PJM. It would be a mistake to consider that level of congestion to be a signal to build transmission.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including

36 PJM, "Manual 38: Operations Planning," Rev. 19 (January 23, 2025) at 19-20.

energy from low cost generation and energy from high cost generation, while only high cost generators are paid the high price at their bus and low cost generators are paid only the low price at their bus.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

For all these reasons, if done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis for transmission projects would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project.

The PJM Regional Transmission Expansion Plan (RTEP) successfully addresses the need for transmission investment to reliably meet load. Together with the requirement that new generation pay interconnection costs, the RTEP process has resulted in the appropriate level of new transmission investment in PJM. There is no evidence that the PJM planning process is not adequate to meet the requirements of the PJM markets. Additional transmission investment is not a panacea. Transmission investment is expensive and long lived and it is essential that transmission investments be carefully planned for clearly identified needs in order to ensure that power markets can continue to provide reliable service at a competitive price.

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[37] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. The correct term is Part V reliability service. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required in order to limit the duration of Part V service for individual units. It is essential that the deactivation provisions of the tariff be evaluated and modified. It is also essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. PJM should consider an expedited queue process for projects that could replace the retiring capacity including the immediate transfer of the retiring unit's CIRs to units in the queue in order to permit generation to compete as an alternative to the current transmission only approach.

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth from data centers. Dominion has presented 44 supplemental project requests to serve the increase in load through the summer of 2025. As part of the supplemental planning process, PJM performs a do no harm analysis. PJM identified the need for additional baseline reinforcements to support the load growth. These baseline reinforcements were addressed in the 2022 RTEP Window 3, when the PJM board approved $1.4 billion of necessary baseline upgrades specific to the Data Center Alley reinforcements.[38] These regional transmission costs were allocated according to Schedule 12 of PJM's Open Access Transmission Tariff (OATT), where costs are shared across all zones by a combination of load ratio share and distribution factor impacts. The transmission owners include these project costs in their base case, and all retail customers in the PJM footprint

37 OATT Part V §114.
38 See "*Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board,*" December 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx>.

pay for those upgrade costs through increased energy bills. The cost allocation of the $1.4 billion in baseline upgrades are assigned to all retail customers and not solely to the customers requesting interconnection.

The high level of customer requests in Data Center Alley resulted in the need for significant baseline reliability upgrades. These costs were allocated per Schedule 12 of the PJM OATT. Not all customer requests result in reliability upgrades. Transmission upgrades for customer requests that are submitted through the supplemental planning process are allocated 100 percent to the zone where they are interconnecting. The transmission owner of that zone then includes those project costs in their rate base, and all retail customers in that zone pay those costs.

The Virginia case illustrates the imposition of transmission costs by data centers on other PJM customers. These additional transmission costs are in addition to the significant capacity market costs imposed on other customers by the actual and forecast addition of large data centers.

The main focus of PJM's planning requirements has been to ensure adequate transmission to allow for generation to reliably serve load. Historically, PJM has had enough excess generation to serve the forecasted load in the RTEP process. In recent years, due in part to the significant increase in load resulting from large load data center interconnection requests and an increase in thermal unit deactivations, meeting forecasted loads and reserves with existing generation has become an issue. In order to solve the RTEP study cases, PJM must make assumptions about the existing and future generation to include in the RTEP model based on the need to serve load. The RTEP analysis first includes all existing generation that is expected to remain in service for the year being studied. When the forecasted load exceeds the expected in service generation, the RTEP analysis includes future generation. Planned generators with a signed interconnection service agreement (ISA) or generation interconnection agreement (GIA), or that cleared a BRA, are included. When the PJM load in the RTEP analysis exceeds the sum of existing generation and generation with an executed final agreement, the RTEP analysis simply adds speculative new generation that is in its Phase 3 system impact study status to meet the load. If needed, additional generation (pre-GIA stage or with a suspended status) may be modeled (assumed) consistent with the procedures noted in Manual 14B.[39] [40] The RTEP analysis is not adequately coordinated with PJM markets analysis including the energy and capacity markets.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[41] [42] As of September 30, 2025, PJM had an installed capacity of 200,952.5 MW, of which 38,366.4 MW (19.1 percent) are coal fired steam units, 57,064.2 MW (28.4 percent) are combined cycle units and 33,452.6 MW (16.6 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 200,952.5 MW of PJM installed capacity, 37,391.3 MW (18.6 percent) are in the AEP Zone, of which 13,463.0 MW (36.0 percent) are coal fired steam units, 9,294.0 MW (24.9 percent) are combined cycle units and 2,071.0 MW (5.5 percent) are nuclear units.

39 See "Review of 2025 RTEP Assumptions," presented at the January 7, 2025 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250107/20250107-item-11---2025-rtep-assumption.pdf>.
40 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).
41 The unit type RICE refers to Reciprocating Internal Combustion Engines.
42 XIC refers to external installed capacity.

Table 12-1 Existing capacity: September 30, 2025 (By zone and unit type (MW))[43]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
ACEC	0.0	781.6	395.5	0.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	5.4	68.8	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	1,264.3
AEP	0.0	9,294.0	4,028.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	3,767.9	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	37,391.3
AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
APS	33.0	2,843.7	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	22.4	0.0	18.3	416.0	0.0	0.0	5,119.0	0.0	0.0	0.0	1,040.0	0.0	10,846.9
ATSI	0.0	5,587.5	1,383.0	183.0	6.4	0.0	0.0	0.0	2,134.0	0.0	5.5	4.7	608.0	0.0	0.0	0.0	325.0	0.0	136.0	0.0	0.0	10,373.1
BGE	3.5	0.0	267.6	215.9	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	4.2	31.1	0.0	0.0	1,273.0	17.5	702.0	57.0	0.0	0.0	4,287.8
COMED	104.5	4,631.1	6,753.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	59.0	0.0	0.0	2,646.0	0.0	0.0	0.0	5,433.2	0.0	30,341.8
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	742.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,674.3
DUKE	12.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	289.9	0.0	0.0	1,252.0	47.0	0.0	0.0	0.0	0.0	2,893.9
DUQ	0.0	306.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	14.4	0.0	0.0	54.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,172.9
DOM	20.0	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	18.0	94.7	5,166.8	0.0	0.0	2,473.2	55.0	0.0	318.4	776.0	0.0	29,332.4
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	86.0	14.1	534.9	0.0	0.0	0.0	710.0	153.0	70.0	0.0	0.0	4,796.9
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,802.0
JCPLC	192.8	2,115.5	748.0	0.0	0.0	0.4	140.0	0.0	0.0	0.0	0.0	0.0	477.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,674.5
MEC	0.0	2,595.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	30.9	430.0	0.0	0.0	80.0	35.0	0.0	60.0	0.0	0.0	3,650.4
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	0.0	0.9	3.0	0.0	0.0	0.0	765.3	0.0	103.0	0.0	0.0	11,978.0
PE	28.4	1,900.0	422.1	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	11.0	326.4	0.0	0.0	4,169.5	610.0	0.0	42.0	1,238.0	0.0	9,543.3
PEPCO	0.0	1,736.5	770.2	204.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	35.6	0.0	0.0	0.0	1,164.1	0.0	52.0	0.0	0.0	3,971.1
PPL	20.0	5,558.5	234.0	36.0	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	220.0	0.0	0.0	1,859.9	3,137.0	0.0	29.0	216.5	0.0	14,589.8
PSEG	7.7	4,223.1	963.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	230.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,113.3
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	100.0	0.0	3,865.6
Total	421.9	57,064.2	24,944.0	2,970.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	13,667.4	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,312.1	0.0	200,952.5

43 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction.

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 200,952.5 MW of installed capacity, 47,504.4 MW (23.6 percent) are in Pennsylvania, of which 6,109.4 MW (12.9 percent) are coal fired steam units, 18,292.2 MW (38.5 percent) are combined cycle units and 8,843.8 MW (18.6 percent) are nuclear units.

Table 12-2 Existing capacity: September 30, 2025 (By state and unit type (MW))

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	19.5	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	50.0	0.0	0.0	0.0	710.0	0.0	70.0	0.0	0.0	2,052.4
IL	104.5	4,631.1	6,753.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	59.0	0.0	0.0	2,646.0	0.0	0.0	0.0	5,433.2	0.0	30,341.8
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	982.6	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	9,547.4
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	382.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	4,101.1
MD	3.5	2,717.0	1,684.5	435.8	0.0	0.0	0.0	0.0	1,716.0	0.0	74.0	18.9	615.8	0.0	0.0	1,273.0	1,181.6	855.0	191.0	349.9	0.0	11,116.0
MI	0.0	994.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,089.4
NC	0.0	165.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	0.0	18.0	0.0	1,181.5	0.0	0.0	0.0	0.0	0.0	0.0	397.0	0.0	2,076.5
NJ	200.5	7,120.2	2,106.7	0.0	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	14.4	776.8	0.0	0.0	0.0	3.0	0.0	179.1	7.5	0.0	14,052.1
OH	12.0	11,574.7	4,626.2	255.2	6.4	0.0	0.0	200.0	2,134.0	0.0	34.0	9.5	3,903.5	0.0	0.0	6,820.0	47.0	0.0	136.0	1,147.7	0.0	30,906.2
PA	49.9	18,292.2	1,545.5	1,334.5	20.6	0.0	1,583.0	1,445.7	8,843.8	168.9	38.5	75.8	1,170.4	0.0	0.0	6,109.4	4,872.3	0.0	234.0	1,719.9	0.0	47,504.4
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VA	20.0	8,973.0	4,092.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	12.0	100.7	4,421.3	0.0	0.0	1,468.2	515.0	0.0	236.4	12.0	0.0	27,564.7
WV	31.5	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	120.0	0.0	0.0	12,484.0	0.0	0.0	0.0	791.7	0.0	14,709.4
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	100.0	0.0	3,865.6
Total	421.9	57,064.2	24,944.0	2,970.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	13,667.4	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,312.1	0.0	200,952.5

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of September 30, 2025. Of the 200,952.5 MW of installed capacity, 72,221.3 MW (35.9 percent) are from units older than 40 years, of which 30,814.3 MW (42.7 percent) are coal fired steam units, 255.0 MW (0.4 percent) are combined cycle units and 25,550.6 MW (35.4 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): September 30, 2025

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Less than 20	421.9	37,832.9	2,566.7	0.0	43.8	32.0	0.0	293.6	0.0	134.5	0.0	150.3	13,667.4	0.0	0.0	2,440.0	82.0	0.0	47.4	12,127.6	0.0	69,840.1
20 to 40	0.0	18,976.3	22,074.8	478.0	0.0	0.0	3,003.0	203.9	7,902.0	34.4	22.0	90.7	0.0	0.0	0.0	5,112.1	73.3	0.0	736.1	184.5	0.0	58,891.1
40 to 60	0.0	255.0	210.5	2,474.7	0.0	0.0	1,789.0	296.5	25,550.6	0.0	140.5	15.8	0.0	0.0	0.0	27,785.5	5,000.1	855.0	57.0	0.0	0.0	64,430.2
Greater than 60	0.0	0.0	92.0	17.7	0.0	0.0	0.0	1,977.1	0.0	0.0	18.0	0.0	0.0	0.0	0.0	3,028.8	2,451.5	0.0	206.0	0.0	0.0	7,791.1
Total	421.9	57,064.2	24,944.0	2,970.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	13,667.4	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,312.1	0.0	200,952.5

Figure 12-1 Capacity (MW) by age (years): September 30, 2025

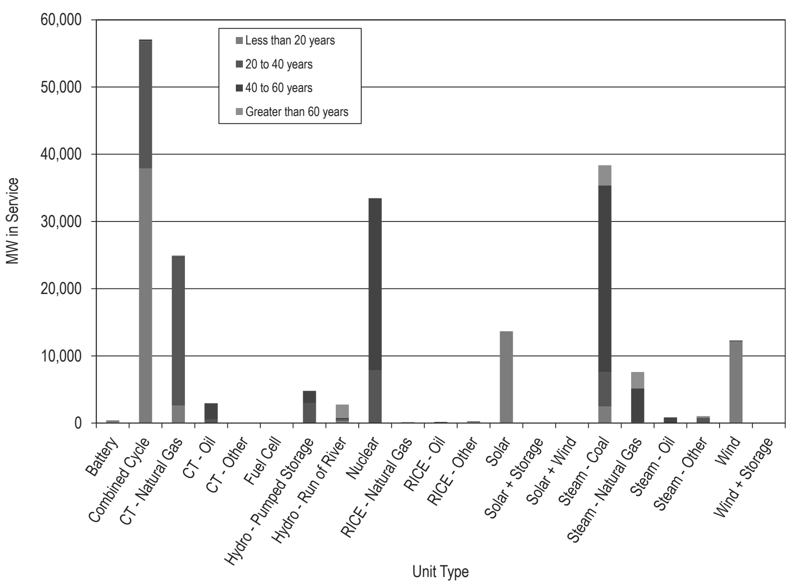


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and September 30, 2025. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through September 30, 2025

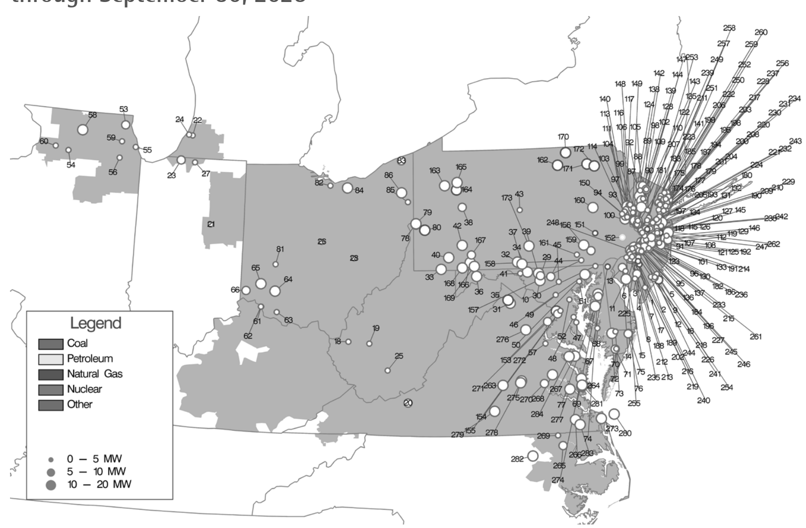


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through September 30, 2025

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	COM MAGID GLOVE 1 BT	111	JC FRENCHTOWN 3 SP	166	PN GARRETT 1 BT	221	PS MATRIX PA SOLAR 2 SP	276	VP REMINGTON 1 SP
2	ACE CATES ROAD 2 SP	57	COM MORRIS 1 LF	112	JC HANOVER 2 SP	167	PN LAUREL HIGHLANDS 2 LF	222	PS MAYWOOD SOLAR 1 SP	277	VP ROCHAMBEAU 1 SP
3	ACE CEDAR BRANCH 1 SP	58	COM ORCHARD 1 LF	113	JC HARMONY 1 SP	168	PN LISTONBURG 1 SP	223	PS METRO HQ 2 SP	278	VP SCOTT - POWHATAN 3 HB
4	ACE EGG HARBOR-KELLOGG 1 FC	59	COM SOLBERG 1 BT	114	JC HIGH STREET 6 SP	169	PN MEYERSDALE 2 BT	224	PS MIDDLESEX 1 SP	279	VP TWITTYS CREEK 1 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	COM STERLING RAIL 1 BT	115	JC HOFFMAN STATION ROAD 2 SP	170	PN MILAN ENERGY 1 D	225	PS MILL CREEK 1 SP	280	VP VIRGINIA OFFSHORE 1 WF
6	ACE GEMS LANDFILL 1 SP	61	DEOK BECKJORD 1 BT	116	JC HOLLAND 4 SP	171	PN NORTH MESHOPPEN 1 CT	226	PS MOORESTOWN 1 SP	281	VP WAN - GLOUCESTER 1 SP
7	ACE KETTLE RUN 1 SP	62	DEOK BECKJORD 2 BT	117	JC HOLLAND-MORRISPA 8 SP	172	PN OXBOW CREEK ENERGY CENTER 1 D	227	PS MT LAUREL 1 SP	282	VP WHITAKERS 1 SP
8	ACE MAYS LANDING 1 SP	63	DEOK BROWN COUNTY 1 LF	118	JC HOLMDEL 9 SP	173	PN WHITETAIL 1 SP	228	PS NEW MILFORD SOLAR 1 SP	283	VP WHITE MARSH - SUFFOLK 1 SP
9	ACE MIDTOWN THERMAL 2 CT	64	DEOK CLINTON 1 BT	119	JC HOWELL 1 SP	174	PS ALDENE SOLAR 1 SP	229	PS NEW ROAD 1 SP	284	VP WOODBINE ROAD 1 SP
10	ACE MONROE - SICKLERVILLE 1 SP	65	DEOK NICKEL - CIN ZOO 1 SP	120	JC HOWELL 4 BT	175	PS ATHENIA SOLAR 1 SP	230	PS NEWARK SOLAR 1 SP		
11	ACE OAK FAIRTON 1 SP	66	DEOK WILLEY 1 BT	121	JC JACOBSTOWN 1 SP	176	PS BAYONNE 1 SP	231	PS NEWARK SOLAR 3 SP		
12	ACE PEAR STREET 1 SP	67	DPL BLOOM ENERGY 1 FC	122	JC JUNCTION ROAD 6 SP	177	PS BAYONNE SOLAR 2 SP	232	PS NIXON LANE 2 SP		
13	ACE PILESGROVE 1 SP	68	DPL BUCKTOWN 1 SP	123	JC LAKEHURST 3 SP	178	PS BELLEVILLE SOLAR 1 SP	233	PS NORTH AMERICAN 4 SP		
14	ACE PILESGROVE 2 SP	69	DPL CHURCH HILL 1 SP	124	JC LEBANON 1 SP	179	PS BENNETTS SOLAR 1 SP	234	PS NORTH AVE SOLAR 1 SP		
15	ACE PITTSGROVE 1 SP	70	DPL COSTEN 1 SP	125	JC LEGLER LANDFILL 7 SP	180	PS BLACK ROCK 1 SP	235	PS OWENS CORNING 1 SP		
16	ACE SEASHORE 1 SP	71	DPL COSTEN 2 SP	126	JC MANALAPAN 1 SP	181	PS BRIDGEWATER SOLAR 2 SP	236	PS PARKLANDS 1 SP		
17	ACE TANSBORO ROAD 1 FC	72	DPL HEBRON 1 SP	127	JC MILLHURST 3 SP	182	PS BUSTLETON 2 SP	237	PS PATERSON PLANK ROAD 1 SP		
18	AEP BALLS GAP 1 BT	73	DPL KUMQUAT 1 SP	128	JC MOUNT OLIVE 3 SP	183	PS CALDWELL PUMP 2 BT	238	PS PENNINGTON 3 BT		
19	AEP CHARLESTON 1 LF	74	DPL PONDTOWN 1 SP	129	JC MUDDY FORGE 3 SP	184	PS CAMPUS DRIVE 2 SP	239	PS PENNINGTON 4 SP		
20	AEP CLOYDS MT 1 LF	75	DPL WORCESTER NORTH 1 SP	130	JC NORTH HANOVER 4 SP	185	PS CEDAR GROVE SOLAR 1 SP	240	PS PENNSAUKEN 1 LF		
21	AEP DEERCREEK 1 SP	76	DPL WORCESTER SOUTH 2 SP	131	JC NORTH PARK 1 SP	186	PS CEDAR LANE FLORENCE 6 SP	241	PS PENNSAUKEN 3 SP		
22	AEP EAST WATERVLIET 1 SP	77	DPL WYE MILLS 1 SP	132	JC NORTH PARK 2 SP	187	PS COOK ROAD SOLAR 2 SP	242	PS PRINCETON HOSPITAL 1 CT		
23	AEP OLIVE 1 SP	78	DUQ BE-PINE 1 SP	133	JC NORTH RUN 11 SP	188	PS COOPER HOSPITAL 1 BT	243	PS RARITAN CENTER 3 SP		
24	AEP ORCHARD HILLS 1 LF	79	DUQ BE-PINE 2 SP	134	JC OLD BRIDGE 1 SP	189	PS COOPER HOSPITAL 15 SP	244	PS REEVES EAST 3 SP		
25	AEP RALEIGH COUNTY 1 LF	80	DUQ PIT MICROGRID 1 CT	135	JC PAUCH 3 SP	190	PS CRANBURY 2 SP	245	PS REEVES SOUTH 1 SP		
26	AEP TRENT 1 BT	81	FE DOVETAIL 1 CT	136	JC PEMBERTON 1 SP	191	PS CROSSWIC 1 SP	246	PS REEVES WEST 4 SP		
27	AEP TWINBRANCH 1 SP	82	FE ERIE COUNTY 1 LF	137	JC PEMBERTON 2 SP	192	PS CROSSWIC 2 SP	247	PS RIDER UNIVERSITY 3 SP		
28	AEP ZANESVILLE 2 LF	83	FE GENEVA 1 LF	138	JC QUAKERTOWN 12 SP	193	PS DEVILSBROOK 1 SP	248	PS RIVER ROAD 2 SP		
29	AP BAKER POINT 1 SP	84	FE LORAIN 1 LF	139	JC QUAKERTOWN 9 SP	194	PS DOREMUS SOLAR 1 SP	249	PS ROSELAND SOLAR 1 SP		
30	AP BIGGS FORD 1 SP	85	FE MAHONING 1 LF	140	JC RICHLINE 3 SP	195	PS E RUTHERFORD SOLAR 1 SP	250	PS RUTGERS GENERATION 1 F		
31	AP DOUBLE TOLLGATE SP	86	FE WARREN-EVERGREEN 1 CT	141	JC RINGOES 1 SP	196	PS EASTAMPTON 1 SP	251	PS SADDLE BROOK SOLAR 1 SP		
32	AP ELK HILL 1 SP	87	JC AUGUSTA 1 SP	142	JC ROY ROAD 5 BT	197	PS EDISON 1 SP	252	PS SPRINGFIELD SOLAR 1 SP		
33	AP GANS 5 SP	88	JC BEAVER RUN 3 SP	143	JC SOUTH COMBE 2 SP	198	PS ESSEX 105 CT	253	PS SUNNYMEADE SOLAR 1 SP		
34	AP HAGERSTOWN 1 SP	89	JC BERKSHIRE 2 SP	144	JC SUSSEX 1 LF	199	PS FAIRLAWN SOLAR 1 SP	254	PS TAYLORS LANE 1 SP		
35	AP HP HOOD 1 CT	90	JC BERNARDS TOWNSHIP 1 SP	145	JC TINTON FALLS 3 SP	200	PS FOODBANK 1 SP	255	PS THOROFARE SOLAR 2 SP		
36	AP JADE MEADOW 1 SP	91	JC BRICKYARD 4 SP	146	JC UPPER FREEHOLD 1 SP	201	PS FORTY NINTH SOLAR 1 SP	256	PS TURNPIKE 1 SP		
37	AP LETZBURG - ELK HILL 2 SP	92	JC BRIGHT ROAD 2 BT	147	JC WANTAGE 2 SP	202	PS GLOUCESTER SOLAR 1 SP	257	PS W CALDWELL SOLAR 1 SP		
38	AP MAHONING CREEK 1 H	93	JC COPPER HILL 4 SP	148	JC WARREN 1 SP	203	PS HACKENSACK 1 SP	258	PS W CALDWELL SOLAR 2 SP		
39	AP MT ST MARYS PV PARK 2 SP	94	JC CYPHERS ROAD 5 SP	149	JC WASHBURN AVE 4 SP	204	PS HIGHLAND PARK 3 BT	259	PS WALDWICK SOLAR 1 SP		
40	AP PECHIN 2 SP	95	JC DIXSOLAR 51 SP	150	ME GLENDON 1 LF	205	PS HIGHLAND PARK 4 SP	260	PS WEST ORANGE SOLAR 1 SP		
41	AP PINESBURG 1 SP	96	JC DIXSOLAR 52 SP	151	ME READING HOSPITAL 1 CT	206	PS HILLSDALE SOLAR 1 SP	261	PS WEST PEMBERTON 1 SP		
42	AP SPRING LANE 1 SP	97	JC DOMIN LANE 1 SP	152	PE MORRIS ROAD 1 D	207	PS HINCHMANS SOLAR 1 SP	262	PS WEST WINDSOR 1 CT		
43	AP STATE COLLEGE 1 BT	98	JC DURBAN AVENUE 1 SP	153	PEP CAPITAL POWER PLANT 1 CT	208	PS HOBOKEN SOLAR 2 SP	263	VP BUCKINGHAM 1 SP		
44	AP UNION BRIDGE 1 SP	99	JC E FLEMINGTON 5 SP	154	PEP ROLLINS AVENUE 3 SP	209	PS HOPEWELL 1 SP	264	VP CAMELLIA - WAN 2 SP		
45	BC ALPHA RIDGE 1 LF	100	JC EAST AMWELL 7 SP	155	PEP SPECTRUM 1 SP	210	PS HOPEWELL 2 BT	265	VP COLICE HALL 1 SP		
46	BC BRIGHTON DAM 1 H	101	JC EGYPT 3 SP	156	PL DART CONTAINER 1-2 LF	211	PS JACKSON SOLAR 1 SP	266	VP GARDNER FARMS 1 SP		
47	BC CHESAPEAKE BEACH 1 BT	102	JC FISCHER 8 SP	157	PL HOLTWOOD 11	212	PS KINSLEY BEAVER 2 SP	267	VP GARDYS MILL ROAD 5 SP		
48	BC FAIRHAVEN 2 BT	103	JC FOUL RIFT 8 SP	158	PL HOLTWOOD 13	213	PS KINSLEY DEPTFORD 1 SP	268	VP HOLLYFIELD 1 SP		
49	BC FAIRVIEW - OTTERPT 1SP	104	JC FOUL RIFT ROAD 1 SP	159	PL KEYSTONE 1 SP	214	PS KUSER SOLAR 1 SP	269	VP MURPHY 1 SP		
50	BC FAIRVIEW - OTTERPT 2SP	105	JC FRANKFORD 4 SP	160	PL PA SOLAR 1 SP	215	PS LANDFILL 5 SP	270	VP NORTHEAST 2 LF		
51	BC KINGSVILLE 1 SP	106	JC FRANKLIN 7 SP	161	PL TURKEY HILL 1 WF	216	PS LAWNSIDE 14 BT	271	VP OCCOQUAN 1 LF		
52	BC MILLERSVILLE 1 LF	107	JC FREEMALL 1 FC	162	PN ALPACA GLORY BARN 1 D	217	PS LEONIA SOLAR 1 SP	272	VP OCCOQUAN 2 LF		
53	COM COUNTRYSIDE 1 LF	108	JC FRENCHES 2 SP	163	PN CARDINAL - CLARKSUM 1 SP	218	PS LUMBERTON STACY HAINES 5 SP	273	VP OCEANA 1 SP		
54	COM DIXON LEE 5 LF	109	JC FRENCHTOWN 1 SP	164	PN CLARION BOARDS 2 CT	219	PS MANTUA CREEK 7 BT	274	VP PULLER 1 SP		
55	COM GRAND RIDGE 6 BT	110	JC FRENCHTOWN 2 SP	165	PN COBALT 1 SP	220	PS MARION SOLAR 1 SP	275	VP QUILLWORT 4 SP		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and September 30, 2025. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): January 1, 2011 through September 30, 2025

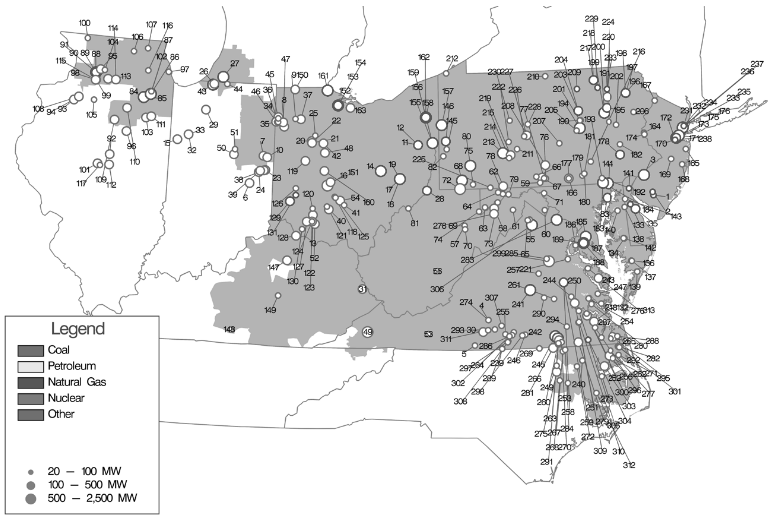


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through September 30, 2025

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	56	AP BEECH RIDGE 2 WF	111	COM PILOT HILL 1 WF	166	JC JUSTIN COURT 10 BT	221	PN MEHOOPANY 2 WF	276	VP MONTROSS 1 SP
2	ACE VINELAND 11 CT	57	AP BEECH RIDGE 3 BT	112	COM RADFORDS RUN 1 WF	167	JC MONTAGUE STORAGE 3 BT	222	PN PATTON 1 WF	277	VP MORGAN CORNER 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	58	AP BLACK ROCK 1 WF	113	COM SHADY OAKS 1 WF	168	JC OAK RIDGE 3 SP	223	PN PGCOGEN 1 CT	278	VP NEW CREEK 1 WF
4	AEP ALTAVISTA 1 SP	59	AP BLAIRS VALLEY 12 SP	114	COM SHADY OAKS 2 WF	169	JC PLUMSTED ENERGY 6 BT	224	PN PGCOGEN 2 CT	279	VP NEWSOMS 1 SP
5	AEP AXTON 1 SP	60	AP BLAKE 1 SP	115	COM WALNUT RIDGE 1 WF	170	JC SAYREVILLE 1 CT	225	PN RINGER HILL 1 WF	280	VP NORGE 2 SP
6	AEP BELLFLOWER 1 SP	61	AP CAPON BRIDGE 1 SP	116	COM WEST CHICAGO 3 BT	171	JC SAYREVILLE 2 CT	226	PN SANDY RIDGE 1 WF	281	VP OAK 1 SP
7	AEP BITTER RIDGE 1 WF	62	AP DANS MOUNTAIN 1 WF	117	COM WHITNEY HILL 2 WF	172	JC SAYREVILLE 3 CT	227	PN SANDY RIDGE 2 WF	282	VP OAK TRAIL 1 SP
8	AEP BLUE CREEK 3 WF	63	AP FAIR WIND 2 WF	118	DAY BUCKEYE PLAINS 2 SP	173	JC SAYREVILLE 4 CT	228	PN SCHOOL HOUSE 1 SP	283	VP PANDA STONEWALL 1 CC
9	AEP BLUE HARVEST 1 SP	64	AP FOURMILE RIDGE 1 WF	119	DAY CLEARVIEW 1 SP	174	JC WARREN GLEN 6 BT	229	PN SUGAR RUN 2 CT	284	VP PECAN 1 SP
10	AEP BLUFF POINT 2 WF	65	AP FOXGLOVE 1 SP	120	DAY CLINTON - EASTFORK 1 SP	175	JC WOODBRIDGE 1 CC	230	PN VIADUCT 1 SP	285	VP PINE GLADE 1 SP
11	AEP CARROLL COUNTY 1 CC	66	AP GREAT COVE 1 SP	121	DAY FAYETTE 1 SP	176	JC WOODBRIDGE 2 CC	231	PS KEARNY 131 CT	286	VP PINEY CREEK 1 SP
12	AEP CARROLL COUNTY 2 CC	67	AP GREAT COVE 2 SP	122	DAY HIGHLAND COUNTY 1 SP	177	ME ADAMS 1 SP	232	PS KEARNY 132 CT	287	VP PLEASANT HILL - SUFFOLK 2 SP
13	AEP DODSON CREEK 1 SP	68	AP GREENE COUNTY 1 CC	123	DAY HIGHLAND COUNTY 2 SP	178	ME BIRDSBORO 1 CC	233	PS KEARNY 133 CT	288	VP POCATY 1 SP
14	AEP DRESDEN 1 CC	69	AP LAUREL MOUNTAIN 1 BT	124	DAY HIGHLAND COUNTY 3-4 SP	179	ME COTTONTAIL 1 SP	234	PS KEARNY 134 CT	289	VP POWELLS CREEK 1 SP
15	AEP FOWLER RIDGE 4 WF	70	AP LAUREL MOUNTAIN 1 WF	125	DAY PICKAWAY COUNTY 1 SP	180	ME COTTONTAIL 2 SP	235	PS KEARNY 141 CT	290	VP POWHATAN 2 SP
16	AEP FOX SQUIRREL 1 SP	71	AP MARLOWE 1 SP	126	DAY TAIT 8 BT	181	ME COTTONTAIL 8 SP	236	PS KEARNY 142 CT	291	VP PUMPKINSEED 1 SP
17	AEP GUERNSEY 11 CC	72	AP NORTH LONGVIEW 1 F	127	DEOK HILLCREST 1 SP	182	ME LYONS 1 SP	237	PS NEWARK ENERGY CENTER 10 CC	292	VP RANCHLAND 2 SP
18	AEP GUERNSEY 21 CC	73	AP PINNACLE 1 WF	128	DEOK MELDAHL DAM 1 H	183	PE DELTA 1-4 CC	238	PS SEWAREN 7 CC	293	VP RENAN 1 SP
19	AEP GUERNSEY 31 CC	74	AP ROTH ROCK 1 WF	129	DEOK MIDDLETOWN ENERGY 1 CC	184	PE DELTA 5-7 CC	239	VP ALTON POST OFFICE 1 SP	294	VP SAPONY 1 SP
20	AEP HARDIN 12 SP	75	AP SOUTH CHESTNUT 1 WF	130	DEOK NESTLEWOOD 1 SP	185	PEP KEYS ENERGY CENTER 1 CC	240	VP AULANDER HOLLOMAN 1 SP	295	VP SHILLELAGH 1 SP
21	AEP HARDIN 23 SP	76	AP ST THOMAS 1 SP	131	DEOK YANKEE 1 F	186	PEP MILLS GROVE 1 SP	241	VP BEAR GARDEN	296	VP SOLIDAGO 1 SP
22	AEP HARDIN 34 SP	77	AP ST THOMAS 2 SP	132	DPL CHERRYDALE 1 SP	187	PEP ST CHARLES - KELSON RIDGE 1 CC	242	VP BLUESTONE FARM 1 SP	297	VP SOUTH BOSTON 1 F
23	AEP HEADWATERS 1 WF	78	AP TWIN RIDGES 1 WF	133	DPL DEMEC - CLAYTON 2 CT	188	PEP ST CHARLES-KELSON RIDGE 1 CC	243	VP BOOKERS MILL 1 SP	298	VP SPANISH GROVE 1 SP
24	AEP HEADWATERS 2 WF	79	AP WARRIOR RUN 2 BT	134	DPL DORCHESTER COUNTY 1 SP	189	PEP ST CHARLES-KELSON RIDGE 2 CC	244	VP BRIEL FARM 1 SP	299	VP SPOTSYLVANIA 1 SP
25	AEP HOG CREEK 1 WF	80	AP WESTMORELAND 1 CC	135	DPL GARRISON EC 1 CC	190	PL EAST CHILLI 1 SP	245	VP BRUNSWICK 1CC	300	VP SPRING GROVE 1 SP
26	AEP HONEYSUCKLE 1 SP	81	AP WILLOW ISLAND 1 H	136	DPL GREAT BAY KINGS CREEK 1 SP	191	PL HAZEL 1 FW	246	VP BUTCHER CREEK 1 SP	301	VP SUMMIT FARMS 1 SP
27	AEP INDECK NILES ENERGY CENTER 1 CC	82	AP WS SARISH - SMITH FRANCIS 1 SP	137	DPL GREAT BAY KINGS CREEK 2 SP	192	PL HOLTWOOD 18	247	VP CARVERS CREEK 1 SP	302	VP SUNNYBROOK FARM 1 SP
28	AEP LONG RIDGE ENERGY 1 CC	83	BC PERRYMAN 6 CT	138	DPL JONES FARM LANE 1 SP	193	PL HOLTWOOD 19	248	VP CAVALIER 1 SP	303	VP TIMBERMILL 1 WF
29	AEP MAMMOTH NORTH 1 SP	84	COM 924 THREE RIVERS EC 1 CC	139	DPL OAK HALL 1 SP	194	PL HUMMEL STATION 1 CC	249	VP CHESTNUT 1 SP	304	VP UNION CAMP 9-10 F
30	AEP MAPLEWOOD 1 SP	85	COM 924 THREE RIVERS EC 2 CC	140	DPL PONDTOWN 2 SP	195	PL HUNLOCK CC	250	VP CHICKAHOMINY 1 SP	305	VP WARDS CREEK 1 SP
31	AEP MARTIN COUNTY 1 SP	86	COM 929 JACKSON 1 CC	141	DPL RED LION 1 FC	196	PL LACKAWANNA COUNTY 1 CC	251	VP CHICKAHOMINY 2 SP	306	VP WARREN COUNTY FRONT ROYAL CC
32	AEP MEADOW LAKE 5 WF	87	COM 929 JACKSON 2 CC	142	DPL RICHFIELD 3 SP	197	PL LACKAWANNA COUNTY 2 CC	252	VP COLONIAL TRAIL WEST 1 SP	307	VP WATER STRIDER 1 SP
33	AEP MEADOW LAKE 6 WF	88	COM 942 NELSON 1 CC	143	DPL TOWNSEND 1 SP	198	PL LACKAWANNA COUNTY 3 CC	253	VP CONETOE 2 SP	308	VP WATLINGTON 1 SP
34	AEP PAULDING 3 WF	89	COM 942 NELSON 2 CC	144	DPL WILDCAT POINT 1 CC	199	PL MOXIE FREEDOM 11 CC	254	VP CORRECTIONAL 1 SP	309	VP WAVERLY 1 SP
35	AEP PAULDING 41 WF	90	COM 942 NELSON 3 CT	145	DUQ GAUCHO 2 SP	200	PL MOXIE FREEDOM 21 CC	255	VP CRYSTAL HILL 1 SP	310	VP WAVERLY 2 SP
36	AEP PAULDING 42 WF	91	COM 942 NELSON 4 CT	146	DUQ MONACA-PENNCHEM 1 CC	201	PL NORTHUMBERLAND 2 SP	256	VP DESERT 1 WF	311	VP WHITEHORN 1 SP
37	AEP POWELL CREEK - LAMMER 1 SP	92	COM ALTA FARMS II 1 WF	147	EKPC BLUEBIRD 1 SP	202	PL PA SOLAR 2 SP	257	VP DESPER 1 SP	312	VP WILKINSON ENERGY CENTER 1 SP
38	AEP RIVERSTART 1 SP	93	COM BISHOP HILL 1 WF	148	EKPC GLOVER CREEK 1 SP	203	PL PATRIOT 1 F	258	VP DOSWELL 2 CT	313	VP WINTERBERRY 1 SP
39	AEP RIVERSTART 3 SP	94	COM BISHOP HILL 2 WF	149	EKPC TURKEY CREEK 1 SP	204	PL PATRIOT 2 F	259	VP DOSWELL 3 CT		
40	AEP ROSS COUNTY 1 SP	95	COM BLOOMING GROVE 1 WF1	150	FE ARCHE ENERGY 1 SP	205	PL PENN 3 SP	260	VP DRY BREAD 1 SP		
41	AEP SALT CITY 1 SP	96	COM BRIGHT STALK 1 WF	151	FE BIG PLAIN 2 SP	206	PL SWIFTWATER 1 SP	261	VP DRY BRIDGE EC 1 BT		
42	AEP SCIOTO RIDGE 1 WF	97	COM GRAND RIDGE 7 BT	152	FE FREMONT 1 SCCT	207	PL WALKER 1 SP	262	VP ELIZABETH CITY 1 SP		
43	AEP ST JOSEPH ENERGY CENTER 1 CC	98	COM GREEN RIVER 1 WF	153	FE FREMONT 2 SCCT	208	PN ASPEN ROAD 1 SP	263	VP FOUNTAIN CREEK 1 SP		
44	AEP ST JOSEPH SOLAR PARK 1 SP	99	COM GREEN RIVER 2 WF	154	FE FREMONT ENERGY CENTER 3 CC	209	PN BEAVER DAM 1 D	264	VP FOXHOUND 1 SP		
45	AEP TIMBER ROAD 1 SP	100	COM HIGHPOINT 11 SP	155	FE HIBBETS MILL SOUTHFIELD 1 CC	210	PN BIG LEVEL 1 WF	265	VP GRASSFIELD 1 SP		
46	AEP TIMBER2 1 WF	101	COM HILLTOPPER 1 WF	156	FE HIBBETS MILL SOUTHFIELD 2 CC	211	PN CHESTNUT FLATS 1 WF	266	VP GREENSVILLE 1 CC		
47	AEP TRISHE 1 WF	102	COM JOLIET 1 BT	157	FE HICKORY RUN 1 CC	212	PN ERIE 1 SP	267	VP GUTENBERG - OCONECHE 1 SP		
48	AEP UNION 1 SP	103	COM KELLY CREEK 1 WF	158	FE LORDSTOWN ENERGY CENTER 1 CC	213	PN FAIRVIEW 1 CC	268	VP HARTS MILL 1 SP		
49	AEP VIRGINIA CITY 1 F	104	COM LEE DEKALB 3 BT	159	FE LORDSTOWN ENERGY CENTER 2 CC	214	PN FAIRVIEW 2 CC	269	VP HAWTREE CREEK 1 SP		
50	AEP WILDCAT 1A WF	105	COM LONE TREE 3 WF	160	FE MADISON FIELDS 1 SP	215	PN HIGHLAND NORTH 2 WF	270	VP IVORY LANE 1 SP		
51	AEP WILDCAT 1B WF	106	COM MARENGO 1 BT	161	FE OREGON ENERGY CENTER 1 CC	216	PN LAUREL HILLS 1 WF	271	VP IVY NECK 2 SP		
52	AEP WILLOWBROOK 1 SP	107	COM MCHENRY 1 BT	162	FE TRUMBULL EC 1 CC	217	PN LIBERTY ASYLUM 10 F	272	VP KELFORD 1 SP		
53	AEP WYTHE COUNTY 1 SP	108	COM MIDLAND 1 WF	163	FE WHEATSBOROUGH 1 SP	218	PN LIBERTY ASYLUM 20 F	273	VP MACKEYS ALBERMAE 1 SP		
54	AEP YELLOWBUD 1 SP	109	COM MINONK 1 WF	164	JC EDGE ROAD 5 BT	219	PN MAPLE HILL-FIDDLERS 1 SP	274	VP MECHANICSVILLE 2 SP		
55	AP BARTONSVILLE 1 SP	110	COM OTTER CREEK 1 WF	165	JC HAMILTON ROAD 5 SP	220	PN MEHOOPANY 1 WF	275	VP MOCCASIN CREEK - FERN 1 SP		

Generation Retirements[44] [45] [46]

Generating units generally plan to retire when they are not economic and do not expect to be economic. Generating units may also plan to retire if environmental restrictions make it too costly to comply or impossible to comply. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio.[47] The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions. The U. S. Department of Energy does have the authority to temporarily order generating plants to continue operating under section 202(c) of the Federal Power Act in the event of emergency or reliability issues.[48]

Rules that preserve ownership of the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and that period can be further extended, at no cost, if the CIRs are assigned to a new project in the interconnection queue at the same point of interconnection.[49] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. Reforms that require the holders of CIRs to use or lose them, and that terminate CIRs on the date of retirement, would make new entry appropriately more attractive. There is no good economic and policy rationale for extending ownership rights to CIRs for inactive units. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[50] The MMU recognized the progress made in this rule change, but it did not fully address the issues. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors or to exercise market power by requiring high payments for CIRs. The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid.

Generation Retirements 2011 through 2030

Table 12-6 shows that as of September 30, 2025, there were 64,079.0 MW of generation that have been, or are planned to be, retired from 2011 through 2030, of which 46,526.8 MW (72.6 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

44 See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2025) <https://www.pjm.com/planning/service-requests/gen-deactivations>.
45 Generation retirements reported in this section do not include external units. Therefore, retirement totals reported in this section may not match totals reported elsewhere in this report where external units are included.
46 For additional information on canceled unit retirement requests, see *2025 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity, "Timing of Unit Retirements".
47 See OATT Part V and Attachment M–Appendix § IV.
48 See 16 U.S.C. § 824a(c).
49 See OATT § 230.3.3.
50 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2030

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,166.5	1,016.0	148.0	108.0	0.0	0.0	5,542.7
Retirements 2019	0.0	0.0	346.8	51.4	6.4	0.0	0.0	0.0	805.0	0.0	0.0	15.9	0.0	0.0	0.0	4,110.5	100.3	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	786.0	60.0	0.0	0.0	3,255.0
Retirements 2021	4.0	118.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,310.3
Retirements 2022	41.0	240.5	99.0	360.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.6	0.0	0.0	0.0	5,385.0	0.0	0.0	0.0	0.0	0.0	6,162.4
Retirements 2023	0.0	114.0	52.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	19.2	0.0	0.0	0.0	4,380.0	1,326.0	800.0	0.0	0.0	0.0	6,727.8
Retirements 2024	28.5	0.0	149.2	108.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7	0.0	0.0	0.0	180.0	0.0	0.0	50.0	0.0	0.0	527.4
Retirements 2025	33.4	0.0	380.0	12.9	0.0	0.0	0.0	0.0	0.0	0.0	2.0	15.0	2.5	0.0	0.0	410.0	126.0	0.0	0.0	0.0	0.0	981.8
Planned Retirements (October 1, 2025 and later)	0.0	16.5	1,740.0	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,117.0	760.0	702.0	0.0	0.0	0.0	8,351.9
Total	147.9	914.0	4,705.1	2,322.5	22.0	0.0	0.5	0.0	1,419.5	0.0	82.1	162.9	2.5	0.0	0.0	46,526.8	4,300.8	3,160.0	302.0	10.4	0.0	64,079.0

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2030, while Table 12-8 shows these retirements by state. Of the 64,079.0 MW of units that has been, or are planned to be, retired from 2011 through 2030, 46,526.8 MW (72.6 percent) are coal fired steam units. These coal fired steam units have an average age of 52.2 years and an average size of 238.6 MW. Over half of the retiring coal fired steam units, 51.1 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2030

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	12	12.3	8.2	147.9	0.2%
Combined Cycle	8	114.3	27.0	914.0	1.4%
Combustion Turbine	159	31.1	35.2	7,049.6	11.0%
Natural Gas	84	56.0	39.5	4,705.1	7.3%
Oil	69	33.7	47.0	2,322.5	3.6%
Other	6	3.7	19.2	22.0	0.0%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	2	709.8	47.2	1,419.5	2.2%
RICE	46	5.2	26.3	245.0	0.4%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	17	4.8	39.3	82.1	0.1%
Other	29	5.6	13.2	162.9	0.3%
Solar	0	0.0	0.0	0.0	0.0%
Solar + Storage	0	0.0	0.0	0.0	0.0%
Solar + Wind	0	0.0	0.0	0.0	0.0%
Steam	239	197.2	46.1	54,289.6	84.7%
Coal	195	238.6	52.2	46,526.8	72.6%
Natural Gas	26	165.4	57.8	4,300.8	6.7%
Oil	9	351.1	49.1	3,160.0	4.9%
Other	9	33.6	25.3	302.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0.0	0.0	0.0	0.0%
Total	469	136.6	44.0	64,079.0	100.0%

Figure 12-4 is a map of unit retirements from 2011 through 2030, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2030

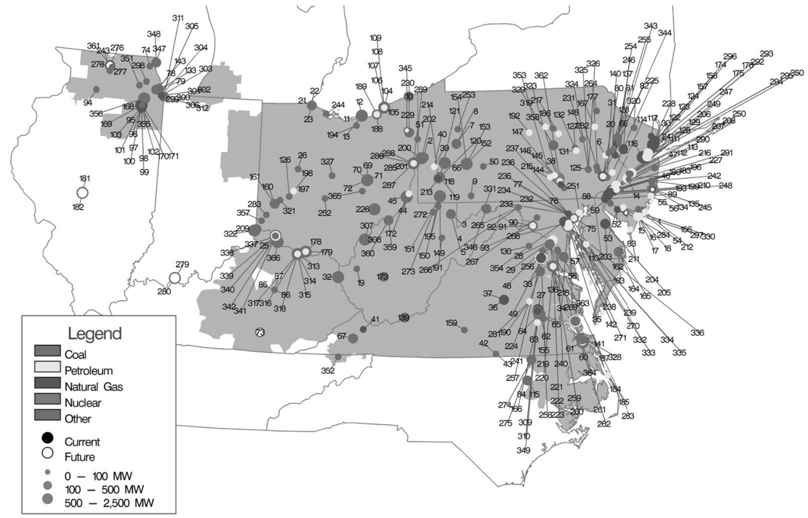


Table 12-8 Retirements (MW) by unit type and state: 2011 through 2030

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	664.0	136.0	0.0	0.0	0.0	0.0	816.4
IL	45.5	0.0	2,095.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.7	0.0	0.0	0.0	3,926.1	1,326.0	0.0	0.0	0.0	0.0	7,429.2
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,602.0	0.0	0.0	0.0	0.0	0.0	3,602.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,111.0	0.0	0.0	0.0	0.0	0.0	1,111.0
MD	20.0	0.0	347.5	274.9	1.6	0.0	0.0	0.0	0.0	0.0	2.0	3.2	0.0	0.0	0.0	4,521.0	297.0	702.0	0.0	0.0	0.0	6,169.2
NC	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	0.0	355.5
NJ	0.0	579.5	2,060.3	1,066.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	36.6	2.5	0.0	0.0	2,001.9	932.5	148.0	10.0	0.0	0.0	7,466.9
OH	52.0	16.5	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	46.7	0.0	0.0	0.0	16,607.4	0.0	0.0	0.0	0.0	0.0	17,061.9
PA	1.0	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	15.9	20.5	0.0	0.0	0.0	7,180.0	1,046.3	176.0	109.0	10.4	0.0	9,857.8
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	23.9	20.1	0.0	0.0	0.0	3,897.9	563.0	1,586.0	133.0	0.0	0.0	6,650.6
WV	29.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,691.0	0.0	0.0	0.0	0.0	0.0	2,720.4
Total	147.9	914.0	4,705.1	2,322.5	22.0	0.0	0.5	0.0	1,419.5	0.0	82.1	162.9	2.5	0.0	0.0	46,526.8	4,300.8	3,160.0	302.0	10.4	0.0	64,079.0

Table 12-9 Unit identification for map of unit retirements: 2011 through 2030

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Chesapeake 7-10	121	Elrama 4	181	Kincaid Unit 1	241	Occoquan 1 LF	301	Southeast Chicago CT5	361	Winnebago Landfill
2	AES Beaver Valley	62	Chesterfield 3	122	Essex 10-11	182	Kincaid Unit 2	242	Ocean County LF	302	Southeast Chicago CT6	362	York Generation Facility
3	Albright 1	63	Chesterfield 4	123	Essex 12	183	Kinsley Landfill	243	Orchard Hills LF	303	Southeast Chicago CT7	363	Yorktown 1-2
4	Albright 2	64	Chesterfield 5	124	Essex 9	184	Kitty Hawk GT 1	244	Ottawa County Project	304	Southeast Chicago CT8	364	Yorktown 3
5	Albright 3	65	Chesterfield 6	125	Evergreen Power United Corstack	185	Kitty Hawk GT 2	245	Oyster Creek	305	Southeast Chicago GT10	365	Zanesville Landfill
6	Allentown CT 1-4	66	Cheswick 1	126	FE DOVETAIL 1 CT	186	Koppers Co. IPP	246	PL MARTINS CREEK 1-4 CT	306	Southeast Chicago GT9	366	Zimmer 1
7	Armstrong 1	67	Clinch River 3	127	FRACKVILLE WHEELABRATOR 1	187	Lake Kingman	247	Parlin NUG	307	Sporn 1-4		
8	Armstrong 2	68	Columbia Dam Hydro	128	Fairless Hills Landfill A	188	Lake Shore 18	248	Pedricktown Cogen CC	308	Sporn 5		
9	Arnold (Green Mtn.) Wind Farm	69	Conesville 3	129	Fairless Hills Landfill B	189	Lake Shore EMD	249	Pennsbury Generator Landfill 1	309	Spruance NUG1 (Rich 1-2)		
10	Ashtabula 5	70	Conesville 4	130	Fauquier County Landfill	190	Lanier 1 CT	250	Pennsbury Generator Landfill 2	310	Spruance NUG2 (Rich 3-4)		
11	Avon Lake 10	71	Conesville 5	131	Fishbach CT 1	191	Laurel Mountain Battery	251	Perryman 2	311	State Line 3		
12	Avon Lake 7	72	Conesville 6	132	Fishbach CT 2	192	Lock Haven CT 1	252	Picway 5	312	State Line 4		
13	Avon Lake 9	73	Cooper 1	133	Fisk Street 19	193	Logan	253	Piney Creek NUG	313	Stuart 1		
14	BC Landfill	74	Countryside Landfill	134	Forked River Unit 1	194	Lorain 1 LF	254	Portland 1	314	Stuart 2		
15	BL England 1	75	Crane 1	135	Forked River Unit 2	195	MEA NUG (WVU)	255	Portland 2	315	Stuart 3		
16	BL England 2	76	Crane 2	136	GUDE Landfill	196	MH50 Markus Hook Co-gen	256	Possum Point 3	316	Stuart 4		
17	BL England 3	77	Crane GT1	137	Gilbert 1-4	197	Mad River CTs A	257	Possum Point 4	317	Stuart Diesels 1-4		
18	BL England Diesel Units 1-4	78	Crawford 7	138	Glen Gardner 1-8	198	Mad River CTs B	258	Possum Point 5	318	Stuart Diesels 1-4		
19	Balls Gap Battery Facility	79	Crawford 8	139	Glen Lyn 5-6	199	Manchester 1 LF	259	Potomac River 1	319	Sunbury 1-4		
20	Barbados AES Battery	80	Cromby 1	140	Glendon LF	200	Mansfield 1	260	Potomac River 2	320	Sussex County LF		
21	Bay Shore 2	81	Cromby 2	141	Gosport 1 F	201	Mansfield 2	261	Potomac River 3	321	Tait Battery		
22	Bay Shore 3	82	Cromby D	142	Gould Street Generation Station	202	Mansfield 3	262	Potomac River 4	322	Tanners Creek 1-4		
23	Bay Shore 4	83	Cumberland CT 1	143	Grand Ridge Energy IV battery component	203	McKee 1	263	Potomac River 5	323	Three Mile Island Unit 1		
24	Bayonne Cogen Plant (CC)	84	DINWIDDIE 1 CT	144	Harrisburg 4 CT	204	McKee 2	264	Pottstown LF (Moser)	324	Titus 1		
25	Beckjord Battery Unit 2	85	Dale 1-2	145	Harrisburg CT 1	205	McKee 3	265	R Paul Smith 3	325	Titus 2		
26	Bellefontaine Landfill Generating Station	86	Dale 3	146	Harrisburg CT 2	206	Mercer 1	266	R Paul Smith 4	326	Titus 3		
27	Bellemeade	87	Dale 4	147	Harrisburg CT 3	207	Mercer 2	267	Reichs Ford Road Landfill Generator	327	Trent Battery Storage		
28	Benning 15	88	Deepwater 1	148	Harwood 1-2	208	Mercer 3	268	Riverside 4	328	VP Virginia Beach		
29	Benning 16	89	Deepwater 6	149	Hatfield's Ferry 1	209	Miami Fort 6	269	Riverside 6	329	Viking Energy NUG		
30	Bergen 3	90	Dickerson CT1	150	Hatfield's Ferry 2	210	Mickleton CT1	270	Riverside 7	330	Vineland West CT		
31	Bethlehem Renewable Energy Generator (Landfill)	91	Dickerson Unit 1	151	Hatfield's Ferry 3	211	Middle 1-3	271	Riverside 8	331	WARRIOR RUN 2 BT		
32	Big Sandy 2	92	Dickerson Unit 2	152	Homer City 1	212	Missouri Ave B,C,D	272	Riversville 5	332	Wagner 1		
33	Birchwood Plant	93	Dickerson Unit 3	153	Homer City 2	213	Mitchell 2	273	Riversville 6	333	Wagner 2		
34	Brandon Shores 1	94	Dixon Lee Landfill Generator	154	Homer City 3	214	Mitchell 3	274	Roanoke Valley 1	334	Wagner 3		
35	Brandon Shores 2	95	ELWOOD CT 1	155	Hopewell James River Cogeneration	215	Modern Power Landfill NUG	275	Roanoke Valley 2	335	Wagner 4		
36	Bremo 3	96	ELWOOD CT 2	156	Howard Down 10	216	Monmouth NUG landfill	276	Rockford CT11	336	Wagner CT 1		
37	Bremo 4	97	ELWOOD CT 3	157	Hudson 1	217	Montour ATG	277	Rockford CT12	337	Walter C Beckjord 1		
38	Brunner Island Diesels	98	ELWOOD CT 4	158	Hudson 2	218	Morgantown CT 5	278	Rockford CT21	338	Walter C Beckjord 2		
39	Brunot Island 1B	99	ELWOOD CT 5	159	Hurt NUG	219	Morgantown CT 6	279	Rockport Unit 1	339	Walter C Beckjord 3		
40	Brunot Island 1C	100	ELWOOD CT 6	160	Hutchings 1-3, 5-6	220	Morgantown CT1	280	Rockport Unit 2	340	Walter C Beckjord 4		
41	Buchanan Units 1 and 2	101	ELWOOD CT 7	161	Hutchings 4	221	Morgantown CT2	281	Rockville CT	341	Walter C Beckjord 5-6		
42	Buggs Island 1 (Mecklenberg)	102	ELWOOD CT 8	162	Indian River CT10	222	Morgantown Unit 1	282	Rolling Hills Landfill Generator	342	Walter C Beckjord GT 1-4		
43	Buggs Island 2 (Mecklenberg)	103	ELWOOD CT 9	163	Indian River 1	223	Morgantown Unit 2	283	SMART Paper	343	Warren County Landfill		
44	Burger 3	104	Eastlake 1	164	Indian River 3	224	Morris Landfill Generator	284	Salem County LF	344	Warren County NUG		
45	Burger EMD	105	Eastlake 2	165	Indian River 4	225	Morris Road 1 D	285	Sammis 1-4	345	Warren Evergreen CT1		
46	Burlington 8,11	106	Eastlake 3	166	Ingenco Petersburg	226	Muskingum River 1-5	286	Sammis Diesel Units	346	Warrior Run		
47	Burlington 9	107	Eastlake 4	167	Jenkins CT 1-2	227	National Park 1	287	Sammis Unit 5	347	Waukegan 7		
48	Buzzard Point East Banks 1,2,4-8	108	Eastlake 5	168	Joliet 6	228	New Bay Cogen CC	288	Sammis Unit 6	348	Waukegan 8		
49	Buzzard Point West Banks 1-9	109	Eastlake 6	169	Joliet 7	229	Niles 1	289	Sammis Unit 7	349	Weakley CT		
50	Cambria CoGen	110	Easton Diesel Unit 8	170	Joliet 8	230	Niles 2	290	Schuylkill 1	350	Werner 1-4		
51	Carbon Limestone LF	111	Eddystone 1	171	Joliet Energy Storage	231	Northeastern Power NEPCO	291	Schuylkill Diesel	351	West Chicago Energy Storage		
52	Carlls Corner CT1	112	Eddystone 2	172	Kammer 1-3	232	Notch Cliff GT1	292	Sewaren 1	352	West Kingsport LF		
53	Carlls Corner CT2	113	Eddystone Unit 3	173	Kanawha River 1-2	233	Notch Cliff GT2	293	Sewaren 2	353	West Shore CT 1-2		
54	Cates Road Solar	114	Eddystone Unit 4	174	Kearny 10	234	Notch Cliff GT3	294	Sewaren 3	354	Westport 5		
55	Cedar 1	115	Edgecomb NUG (Rocky 1-2)	175	Kearny 11	235	Notch Cliff GT4	295	Sewaren 4	355	Will County 3		
56	Cedar 2	116	Edison 1-3	176	Kearny 9	236	Notch Cliff GT5	296	Sewaren 6	356	Will County 4		
57	Chalk Point Unit 1	117	Elmwood Park Power	177	Keystone Recovery (Units 1 - 7)	237	Notch Cliff GT6	297	Sherman Avenue CT1	357	Willey Energy Storage		
58	Chalk Point Unit 2	118	Elrama 1	178	Killen 2	238	Notch Cliff GT7	298	Solberg 1 BT	358	Williamsport-Lycoming CT 1-2		
59	Chambers CCLP	119	Elrama 2	179	Killen CT	239	Notch Cliff GT8	299	Southeast Chicago CT11	359	Willow Island 1		
60	Chesapeake 1-4	120	Elrama 3	180	Kimberly Clark Generator	240	Oaks Landfill	300	Southeast Chicago CT12	360	Willow Island 2		

Current Year Generation Retirements

Table 12-10 shows that in the first nine months of 2025, 981.8 MW of generation retired. The largest generator that retired in the first nine months of 2025 was the 410.0 MW Indian River 4 coal fired steam unit located in the DPL Zone. Of the 981.8 MW of generation that retired in the first nine months of 2025, 410.0 MW (41.8 percent) were located in the DPL Zone.

Table 12-10 Unit deactivations: January through September, 2025

Owner	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	44	24-Feb-25
NextEra Energy, Inc.	Manchester 1 LF	5.0	RICE-Other	JCPLC	28	01-Apr-25
The Goldman Sachs Group Inc.	Cates Road Solar	2.5	Solar	ACEC	13	01-Apr-25
Pennoni Associates Inc	Morris Road 1 D	2.0	RICE-Oil	PECO	13	31-May-25
Hull Street Energy LLC	ELWOOD CT 8	150.0	CT-Natural Gas	COMED	24	01-Jun-25
Hull Street Energy LLC	ELWOOD CT 9	150.0	CT-Natural Gas	COMED	24	01-Jun-25
Talen Energy Corporation	Wagner 1	126.0	Steam-Natural Gas	BGE	69	01-Jun-25
Talen Energy Corporation	Wagner CT 1	12.9	CT-Oil	BGE	58	01-Jun-25
NextEra Energy, Inc.	Ocean County LF	9.1	RICE-Other	JCPLC	28	01-Jul-25
The AES Corporation	Laurel Mountain Battery	27.4	Battery	APS	14	01-Jul-25
LS Power Equity Partners, L.P.	Buchanan Units 1 and 2	80.0	CT-Natural Gas	AEP	23	02-Jul-25
Sumitomo Corporation	Willey Energy Storage	6.0	Battery	DUKE	10	02-Sep-25
Renergy, Inc.	FE DOVETAIL 1 CT	0.9	RICE-Other	ATSI	9	24-Sep-25
Total		981.8				

Planned Generation Retirements

Table 12-11 shows that, as of September 30, 2025, there were 8,351.9 MW of generation that have requested retirement after September 30, 2025. Of the 8,351.9 MW requesting retirement, 5,117.0 MW (61.3 percent) are coal fired steam units. Of the 8,351.9 MW of planned retirements, 2,620.0 MW (31.4 percent) are located in the AEP Zone. Of the generation requesting retirement in the AEP Zone, 2,620.0 MW (100.0 percent) are coal fired steam units.

Table 12-11 Planned retirement of units: September 30, 2025

Owner	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
ArcelorMittal	Warren Evergreen CT1	16.5	Combined Cycle	ATSI	01-Oct-25
Constellation Energy Generation, LLC	Eddystone Unit 3	380.0	Steam-Natural Gas	PECO	26-Nov-25
Constellation Energy Generation, LLC	Eddystone Unit 4	380.0	Steam-Natural Gas	PECO	26-Nov-25
Hull Street Energy LLC	ELWOOD CT 1	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 2	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 3	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 4	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 5	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 6	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 7	150.0	CT-Natural Gas	COMED	01-Jun-26
NRG Energy Inc	Indian River CT10	16.4	CT-Oil	DPL	01-Jun-26
Bridgepoint Group PLC	Cumberland CT 1	90.8	CT-Natural Gas	ACEC	01-Jun-27
Hull Street Energy LLC	Forked River Unit 1	34.0	CT-Natural Gas	JCPLC	01-Jun-27
Hull Street Energy LLC	Forked River Unit 2	31.0	CT-Natural Gas	JCPLC	01-Jun-27
LS Power Equity Partners, L.P.	Rockford CT11	149.1	CT-Natural Gas	COMED	01-Jun-27
LS Power Equity Partners, L.P.	Rockford CT12	147.8	CT-Natural Gas	COMED	01-Jun-27
LS Power Equity Partners, L.P.	Rockford CT21	153.0	CT-Natural Gas	COMED	01-Jun-27
Bridgepoint Group PLC	Sherman Avenue CT1	84.3	CT-Natural Gas	ACEC	01-Jun-27
Vistra Energy Corp	Kincaid Unit 1	554.0	Steam-Coal	COMED	30-Nov-27
Vistra Energy Corp	Kincaid Unit 2	554.0	Steam-Coal	COMED	30-Nov-27
American Electric Power Company, Inc.	Rockport Unit 1	1,320.0	Steam-Coal	AEP	31-Dec-28
American Electric Power Company, Inc.	Rockport Unit 2	1,300.0	Steam-Coal	AEP	31-Dec-28
Talen Energy Corporation	Brandon Shores 1	635.0	Steam-Coal	BGE	31-May-29
Talen Energy Corporation	Brandon Shores 2	638.0	Steam-Coal	BGE	31-May-29
Talen Energy Corporation	Wagner 3	305.0	Steam-Oil	BGE	31-May-29
Talen Energy Corporation	Wagner 4	397.0	Steam-Oil	BGE	31-May-29
East Kentucky Power Cooperative, Inc	Cooper 1	116.0	Steam-Coal	EKPC	31-Dec-30
Total		8,351.9			

In addition to the 8,351.9 MW of announced unit retirements as of September 30, 2025, there are significantly more unit retirements expected as a result of environmental regulations and for economic reasons.[51]

51 For more information, see *2025 Quarterly State of the Market Report for PJM: January through September*, Section 7: Net Revenue.

Generation Queue[52]

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[53] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants. But the behavior of project developers also creates issues with queue management and exacerbates the barriers.

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. Projects submitted to the queue undergo a deficiency review to ensure that all required information is provided. A queue position is assigned once the project has met the submission requirements. Projects that do not meet submission requirements are removed from the queue.

In 2022, after a lengthy stakeholder process (Interconnection Process Reform Task Force (IPRTF)) PJM filed significant changes to improve overall queue management. On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions modifying how PJM manages the new services queue.[54] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[55] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts.

52 Unless otherwise noted, the queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
53 See OATT Parts IV & VI.
54 181 FERC ¶ 61,162 (2022).
55 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

The new cycle process also includes defining progress to completion through three phases, with a customer decision at the end of each. The new cycle process requires a stronger definition of site control, and includes readiness deposits (some of which are nonrefundable) based on the phase of development. Additional process modifications include limits to technology changes, improvements to the application review phase, removal of optional interconnection study processes, modifications to the study schedules to reduce the number of restudies required in the event of project modifications, adjusting the queue window schedule to coincide with the previous clusters' milestones, and modifications to cost responsibility by assigning responsibility to all projects within a queue cycle. The new cycle process should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

The transition to the new cycle process began on July 10, 2023. The last open series queue prior to July 10, 2023, was AJ1. The new cycle process includes a transition which treats projects based on their series queue status. All projects through series queue window AD2 will continue as part of the series queue process. The transition process assigned series queue projects in queue windows AE1 through AH1 to transition cycle 1 (TC1) and transition cycle 2 (TC2) and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. The start of the transition to the new cycle process on July 10, 2023, also started the 60 day readiness review period for active projects in the AE1 through AG1 queues. During this time, project developers provided evidence of site control and provided the necessary readiness deposit.[56] Those projects in the AE1 through AG1 series queues that had not yet received an interconnection service agreement or a wholesale market power agreement and also met readiness requirements were reviewed to determine if they were eligible for the fast track process, or if they will be studied as part of transition cycle 1. Of the 734 projects in queues AE1 through AG1 reviewed, 306 projects (41.7 percent) qualified for the expedited process, 312 projects (42.5 percent) were assigned to transition cycle 1 and 116 projects (15.8 percent) were withdrawn from the queue.

56 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 02 (July 23, 2025) for a complete list of all readiness requirements.

The transition process must also account for the fact that PJM significantly underestimated the level of CIRs required for intermittent resources. PJM had required only CIRs equal to the ELCC rating of intermittent resources when in fact those resources required CIRs equal to the maximum output that contributed to the ELCC rating. In general, CIRs were understated by the difference between the ELCC derating factor and the maximum facility output of the intermittent resource. PJM filed revised rules and FERC approved them.[57] PJM has created a process to permit such resources to increase their CIRs to the required level through appropriate investments in interconnection facilities. This process will occur coincident with the start of the new service request Cycle 1.

The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[58]

New Service Requests Serial Process

Interconnection Process Studies and Agreements[59]

Prior to implementation of the new cycle process, PJM used a serial service process. In the study stage of the interconnection planning serial process, a series of studies were performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-12 is an overview of the studies PJM performed in the study stage of the interconnection serial process. System impact and facilities studies were often redone when a project was withdrawn in order to determine the impact on the projects remaining in the queue.

57 183 FERC ¶61,009.
58 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.
59 See "PJM Manual 14A: New Services Request Process," Rev. 30 (July 26, 2023) for a complete explanation of the interconnection process studies and agreements.

Table 12-12 Interconnection planning serial process: study stage

Study	Purpose
Feasibility Study	The feasibility study determines preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.
System Impact Study	The system impact study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system. The study identifies the system constraints related to the project and the necessary attachment facilities, local upgrades, and network upgrades. The study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.
Facilities Study	In the facilities study, stability analysis is performed and the system impact study results are modified as necessary to reflect changes in the characteristics of other projects in the queue.

In addition to the feasibility, system impact and facilities studies, PJM would also perform additional studies under certain circumstances. These studies included the affected systems study, interim deliverability study and the long term firm transmission studies. Table 12-13 is an overview of the additional studies PJM could have performed.

Table 12-13 Interconnection planning serial process: study stage – additional studies

Study	Purpose
Affected System Study	PJM and its neighboring balancing authorities conduct interconnection studies to determine the impacts of interconnection requests on the neighboring transmission system.
Interim Deliverability Studies	Interim deliverability studies are conducted on a periodic basis in support of RPM auctions and other interconnection studies to determine if a new facility may come on line prior to its scheduled date. These studies evaluate the available system capability and provide the customer(s) with the availability of service by planning year. Interim deliverability studies use the same criteria used for the evaluation of the need for reinforcements associated with a project under study.
Long Term Firm Transmission Studies	Transmission service requests that extend beyond the available transfer capability horizon of 18 months are evaluated along with the other requests for service in the PJM new services queue to ensure deliverability. Long term firm transmission studies follow the same feasibility, system impact and facilities study process as new generation.

After the completion of a facility study, the project would enter the construction stage of the interconnection process. The final agreements required depended on the type of project. These agreements included a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), Wholesale Market

Participant Agreement (WMPA) or Transmission Service Agreement (TSA). Table 12-14 is an overview of the agreements in the construction stage of the interconnection serial process.

Table 12-14 Interconnection planning serial process: construction stage agreements

Agreement	Purpose
Interconnection Service Agreement (ISA)	An ISA defines the generation or transmission developer's cost responsibility for required system upgrades. For generation interconnection customers, the ISA defines the capacity interconnection rights for a capacity resource and any operational restrictions or other limitations. For transmission interconnection customers, the ISA defines transmission injection and withdrawal rights and applicable incremental delivery, available transfer capability revenue and auction revenue rights.
Interim Interconnection Service Agreements (I-ISA)	If a developer wishes to start project construction activities prior to completion of the generation or transmission interconnection facilities study, the interim ISA would commit the developer to pay all costs incurred for the construction activities being advanced.
Interconnection Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

Planned Generation Additions

There were 8,190 generation request projects submitted in the new service request serial process queue from 1997 until the implementation of the new cycle process on July 10, 2023. As a result of the transition to the new services cycle process, 312 projects were moved to transition cycle 1 (TC1). There were 1,347 projects eligible to resubmit for evaluation in transition cycle 2 (TC2). Of those 1,347 eligible projects, 550 projects resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects did not resubmit, and were withdrawn from the queue. There were 1,070 projects initially entered into the AH2 queue and beyond. Those 1,070 projects are now considered invalid and have been removed from the queue. As a result of the transition to the cycle process, the 8,190 projects in the serial process queue has been reduced to 5,461 projects. Projects that will be evaluated in TC1 and TC2, and those projects no longer eligible to be evaluated in the serial process have been removed from the new service requests serial process metrics. New service requests cycle process metrics are reported separately from the serial process metrics.

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets and from federal and state subsidies and incentives. On September 30, 2025, 43,634.4 MW were in generation request serial queues in the status of active, under construction or suspended, for construction through 2031. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[60]

As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. Table 12-15 shows the total MW in the serial queues by expected completion year and MW changes in the serial queue between December 31, 2024, and September 30, 2025, for ongoing projects, i.e. projects with the status active, under construction or suspended.[61]

60 See "*PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years,*" <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf>.

61 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

Table 12-15 Serial queue comparison by expected completion year (MW): December 31, 2024 and September 30, 2025[62]

			Year Change	
Year	As of 12/31/2024	As of 9/30/2025	MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	0.0	0.0	0.0	0.0%
2012	0.0	0.0	0.0	0.0%
2013	0.0	0.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	0.0	0.0	0.0	0.0%
2016	0.0	0.0	0.0	0.0%
2017	0.0	0.0	0.0	0.0%
2018	44.0	44.0	0.0	0.0%
2019	69.1	0.0	(69.1)	(100.0%)
2020	395.6	0.0	(395.6)	(100.0%)
2021	2,266.9	116.0	(2,150.9)	(94.9%)
2022	3,220.9	0.0	(3,220.9)	(100.0%)
2023	4,141.8	871.8	(3,270.0)	(79.0%)
2024	3,203.3	896.1	(2,307.2)	(72.0%)
2025	8,391.0	4,610.8	(3,780.2)	(45.1%)
2026	11,225.2	13,338.9	2,113.7	18.8%
2027	4,197.3	10,205.2	6,007.9	143.1%
2028	4,152.3	6,810.3	2,658.0	64.0%
2029	1,533.0	4,477.9	2,944.9	192.1%
2030	250.0	1,280.0	1,030.0	412.0%
2031	544.0	983.4	439.4	80.8%
Total	43,634.4	43,634.4	(0.0)	(0.0%)

Table 12-16 shows the project status changes in more detail and how scheduled serial queue MW have changed between December 31, 2024, and September 30, 2025. For example, of the total 35,266.7 MW marked as active on December 31, 2024, 6,999.0 MW were withdrawn, 1,844.9 MW were suspended, 5,916.8 MW started construction, and 34.9 MW went into service by September 30, 2025. Analysis of projects that were suspended on December 31, 2024 show that 1,895.7 MW came out of suspension and are now active as of September 30, 2025.

62 Unless otherwise noted, wind and solar capacity totals in this section have not been adjusted to reflect derating.

Table 12-16 Change in project status (MW): December 31, 2024, to September 30, 2025

		Status at 9/30/2025				
Status at 12/31/2024	Total at 12/31/2024	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2025)	0.0	0.0	0.0	0.0	0.0	0.0
Active	35,266.7	20,471.1	34.9	5,916.8	1,844.9	6,999.0
In Service	91,834.5	0.0	91,257.5	577.0	0.0	0.0
Under Construction	6,770.8	0.0	2,409.3	4,046.5	300.0	15.0
Suspended	12,137.9	1,895.7	65.0	853.9	7,728.6	1,594.8
Withdrawn	463,122.8	0.0	8.0	0.0	0.0	463,114.8
Total	609,132.6	22,366.7	93,774.7	11,394.2	9,873.5	471,723.5

On September 30, 2025, 43,634.4 were in generation request serial queues in the status of active, suspended or under construction. Table 12-17 shows each status by unit type. Of the 22,366.7 MW in the status of active on September 30, 2025, 1,220.0 MW (5.5 percent) were combined cycle projects. Of the 11,394.2 MW in the status of under construction, 1,668.8 MW (14.6 percent) were combined cycle projects and 7,148.9 MW (62.7 percent) were solar projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 43,634.4 MW in the serial queues in the status of active on September 30, 2025, 2,268.3 MW (10.1 percent) were renewable hybrid projects. Of the 11,394.2 MW in the status of under construction, 103.9 MW (0.9 percent) were renewable hybrid projects.

Table 12-17 Current project status (MW) by unit type: September 30, 2025

	Battery	Combined Cycle	CT – Natural Gas	CT – Oil	CT – Other	Fuel Cell	Hydro – Pumped Storage	Hydro – Run of River	Nuclear	RICE – Natural Gas	RICE – Oil	RICE – Other	Solar	Solar + Storage	Solar + Wind	Steam – Coal	Steam – Natural Gas	Steam – Oil	Steam – Other	Wind	Wind + Storage	Total
Active	2,436.2	1,220.0	1,057.7	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	13,772.6	2,268.3	0.0	0.0	0.0	0.0	0.0	1,561.0	0.0	22,366.7
Suspended	584.2	1,270.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,807.5	150.0	0.0	0.0	0.0	0.0	0.0	2,061.8	0.0	9,873.5
Under Construction	405.7	1,668.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	7,148.9	103.9	0.0	36.0	0.0	0.0	0.0	1,926.9	0.0	11,394.2
Total	3,426.1	4,158.8	1,117.7	0.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	26,729.0	2,522.2	0.0	36.0	0.0	0.0	0.0	5,549.7	0.0	43,634.4

A significant shift in the distribution of unit types within the PJM footprint continues to develop as renewable, hybrid and other intermittent resources enter the queue, fewer natural gas fired units enter the queue, and coal fired steam units retire. As of September 30, 2025, of the 43,634.4 MW in the generation request serial queues in the status of active, suspended or under construction, 26,729.0 MW (61.3 percent) were solar projects, 5,549.7 MW (12.7 percent) were wind projects, 5,276.5 MW (12.1 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 2,522.2 MW (5.8 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 36.0 MW (0.08 percent) were coal fired steam projects.

As of September 30, 2025, there were 5,117.0 MW of coal fired steam units and 2,500.0 MW of natural gas units slated for deactivation between October 1, 2025, and December 31, 2030 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure. The growing level of renewables, hybrids and other intermittents will have increasingly significant impacts on the energy and capacity markets.

On September 30, 2025, 31,841.9 MW, on an energy basis, were in generation request serial queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Table 12-18 shows the status by unit type. Of the 31,841.9 MW, 12,683.3 MW (39.8 percent) had not begun construction, 9,873.5 MW (31.0 percent) began construction, but are now suspended and 9,285.2 MW (29.2 percent) are currently under construction. Reaching the final milestone required prior to construction does not mean a project will immediately begin construction or even that it necessarily will ever begin construction.

Table 12-18 Current status (MW) by unit type for projects that have reached the CSA Milestone: September 30, 2025

	Battery	Combined Cycle	CT – Natural Gas	CT – Oil	CT – Other	Fuel Cell	Hydro – Pumped Storage	Hydro – Run of River	Nuclear	RICE – Natural Gas	RICE – Oil	RICE – Other	Solar	Solar + Storage	Solar + Wind	Steam – Coal	Steam – Natural Gas	Steam – Oil	Steam – Other	Wind	Wind + Storage	Total
Active	699.0	1,170.0	618.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,756.0	1,142.3	0.0	0.0	0.0	0.0	0.0	1,297.7	0.0	12,683.3
Suspended	584.2	1,270.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,807.5	150.0	0.0	0.0	0.0	0.0	0.0	2,061.8	0.0	9,873.5
Under Construction	355.7	1,668.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	5,102.5	103.9	0.0	36.0	0.0	0.0	0.0	1,914.3	0.0	9,285.2
Total	1,638.9	4,108.8	678.3	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	18,666.0	1,396.2	0.0	36.0	0.0	0.0	0.0	5,273.7	0.0	31,841.9

Table 12-19 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each serial queue since the beginning of the RTEP process and the total MW that had been included in each queue. All projects in queues A-Z2 are either in service or have been withdrawn. As of September

30, 2025, there were 43,634.4 MW in serial queues that are not yet in service or withdrawn, of which 9,873.5 MW (22.6 percent) are suspended, 11,394.2 MW (26.1 percent) are under construction and 22,366.7 MW (51.3 percent) have not begun construction.

Table 12-19 Serial queue totals by status (MW): September 30, 2025[63]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,102.0	0.0	0.0	17,252.0	26,354.0
B Expired 31-Jan-99	0.0	4,292.4	0.0	0.0	14,958.8	19,251.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,171.6	0.0	0.0	17,961.8	19,133.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	0.0	0.0	8,129.3	10,528.0
O Expired 31-Jul-05	0.0	1,890.2	0.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,290.3	0.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,940.5	0.0	0.0	20,708.9	22,649.4
S Expired 31-Jul-07	0.0	3,598.4	0.0	0.0	12,396.5	15,994.9
T Expired 31-Jan-08	0.0	4,196.5	0.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	716.9	0.0	0.0	16,218.6	16,935.5
U3 Expired 31-Oct-08	0.0	333.0	0.0	0.0	2,635.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	0.0	4,945.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	0.0	0.0	3,641.2	4,631.1
V3 Expired 31-Oct-09	0.0	1,132.0	0.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	0.0	3,708.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	0.0	504.3	0.0	0.0	8,695.9	9,200.2
W4 Expired 31-Jan-11	0.0	1,415.8	0.0	0.0	4,152.6	5,568.4
X1 Expired 30-Apr-11	0.0	1,101.7	0.0	0.0	6,200.6	7,302.3
X2 Expired 31-Jul-11	0.0	3,706.4	0.0	0.0	5,578.4	9,284.7
X3 Expired 31-Oct-11	0.0	109.2	0.0	0.0	7,665.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	0.0	1,795.5	0.0	0.0	6,279.7	8,075.2
Y2 Expired 31-Oct-12	0.0	1,477.2	0.0	0.0	9,636.5	11,113.7
Y3 Expired 30-Apr-13	0.0	1,634.5	0.0	0.0	4,605.2	6,239.6
Z1 Expired 31-Oct-13	0.0	3,283.5	0.0	0.0	4,730.0	8,013.5
Z2 Expired 30-Apr-14	0.0	3,058.6	0.0	0.0	3,037.8	6,096.5
AA1 Expired 31-Oct-14	0.0	4,868.9	123.0	0.0	6,973.4	11,965.3
AA2 Expired 30-Apr-15	550.0	3,031.6	0.0	0.0	12,484.7	16,066.3
AB1 Expired 31-Oct-15	579.0	2,815.6	1,571.0	247.8	15,240.3	20,453.7
AB2 Expired 31-Mar-16	0.0	3,678.5	404.0	92.0	10,968.3	15,142.8
AC1 Expired 30-Sep-16	514.3	5,620.1	893.9	608.7	12,399.0	20,035.9
AC2 Expired 30-Apr-17	823.4	1,524.8	558.8	274.9	9,387.8	12,569.6
AD1 Expired 30-Sep-17	829.0	1,295.7	1,326.7	668.0	7,117.2	11,236.6
AD2 Expired 31-Mar-18	718.0	1,751.1	777.5	1,088.8	15,801.3	20,136.7
AE1 Expired 30-Sep-18	1,495.1	802.4	1,458.9	4,153.4	24,933.1	32,842.8
AE2 Expired 31-Mar-19	3,558.6	1,365.6	1,609.6	1,716.6	20,334.7	28,585.1
AF1 Expired 30-Sep-19	4,825.4	1,212.7	1,074.8	782.0	13,443.8	21,338.8
AF2 Expired 31-Mar-20	3,839.7	393.5	1,124.6	160.8	12,323.2	17,841.7
AG1 Expired 30-Sep-20	4,634.3	76.6	471.4	80.5	13,496.8	18,759.7
AG2 Expired 31-Mar-21	0.0	1.0	0.0	0.0	0.0	1.0
Total	22,366.7	93,774.7	11,394.2	9,873.5	471,723.5	609,132.6

63 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Table 12-20 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of September 30, 2025, 43,634.4 MW were in generation request serial queues for construction through 2031. Table 12-20 also shows the planned retirements for each zone.

Table 12-20 Serial queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): September 30, 2025[64]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	160.9	83.0	0.0	0.0	0.0	0.0	0.0	432.0	0.0	725.9	175.1
	DPL	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	795.8	16.6	0.0	0.0	0.0	0.0	0.0	255.1	0.0	1,076.5	16.4
	JCPLC	310.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	119.2	120.0	0.0	0.0	0.0	0.0	0.0	816.0	0.0	1,365.2	65.0
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	760.0
	PSEG	535.0	51.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	592.1	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	904.0	51.1	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	1,081.9	219.6	0.0	0.0	0.0	0.0	0.0	1,503.1	0.0	3,803.7	1,016.5
SWMAAC	BGE	300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.0	1,975.0
	PEPCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	SWMAAC Total	300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.0	1,975.0
WMAAC	MEC	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	224.6	18.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	262.8	0.0
	PE	160.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,273.2	20.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	1,563.1	0.0
	PPL	170.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	648.2	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	878.2	0.0
	WMAAC Total	350.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,146.0	98.2	0.0	0.0	0.0	0.0	0.0	109.9	0.0	2,704.1	0.0
Non-MAAC	AEP	819.2	1,150.0	0.0	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	12,287.1	1,159.0	0.0	36.0	0.0	0.0	0.0	816.2	0.0	16,318.5	2,620.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	APS	20.0	1,915.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,137.6	380.0	0.0	0.0	0.0	0.0	0.0	160.0	0.0	3,642.6	0.0
	ATSI	0.0	940.0	458.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,417.5	0.0	0.0	0.0	0.0	0.0	0.0	297.7	0.0	3,113.9	16.5
	COMED	180.0	102.7	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,120.9	19.9	0.0	0.0	0.0	0.0	0.0	2,584.6	0.0	4,068.1	2,607.9
	DAY	125.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	806.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	931.3	0.0
	DUKE	52.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	149.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	201.2	0.0
	DLCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0
	DOM	675.7	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,121.6	628.0	0.0	0.0	0.0	0.0	0.0	78.2	0.0	8,072.5	0.0
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	381.0	116.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	1,872.1	4,107.7	1,117.7	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	23,461.1	2,204.4	0.0	36.0	0.0	0.0	0.0	3,936.7	0.0	36,786.6	5,360.4
Total		3,426.1	4,158.8	1,117.7	0.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	26,729.0	2,522.2	0.0	36.0	0.0	0.0	0.0	5,549.7	0.0	43,634.4	8,351.9

Withdrawn Projects

The serial queue contains a substantial number of projects that are not likely to be built. The serial queue process results in a substantial number of projects that are withdrawn. Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage, but the actual calculation of commercial probability factors is less than transparent.[65] The impact and facilities studies are performed using the full amount of planned generation in the queues.

Table 12-21 shows the milestone status when projects were withdrawn, for all withdrawn projects in the serial queue. Of the 3,734 projects withdrawn as of September 30, 2025, 1,577 (42.2 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 3,734 projects withdrawn, 826 projects (22.1 percent) were withdrawn after the completion of a Construction Service Agreement as of September 30, 2025.

64 This data includes only projects with a status of active, under construction, or suspended.
65 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).

Table 12-21 Last milestone at time of withdrawal: January 1, 1997 through September 30, 2025

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days	MW Withdrawn
Never Started	513	13.7%	81	868	53,163.6
Feasibility Study	1,064	28.5%	291	1,633	196,263.0
System Impact Study	907	24.3%	829	3,248	115,206.2
Facilities Study	424	11.4%	1,291	4,107	58,275.1
Construction Service Agreement (CSA) or beyond	826	22.1%	1,502	7,864	48,815.7
Total	3,734	100.0%			471,723.5

Average Time in Serial Queue

Table 12-22 shows the time spent at various stages in the serial queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,254 days, or 3.4 years, between entering a serial queue and going into service. For withdrawn projects, there is an average time of 792 days, or 2.2 years, between entering a serial queue and withdrawing.

Table 12-22 Project serial queue times by status (days): September 30, 2025[66]

Status	Average (Days)	Standard Deviation	Maximum
Active	2,272	422	3,806
In-Service	1,254	867	6,628
Suspended	2,503	404	3,683
Under Construction	2,696	532	4,060
Withdrawn	792	796	7,864

Table 12-23 presents information on the time in the stages of the serial queue for those projects not yet in service or already withdrawn. Of the 460 projects in the serial queue, in the status of active, under construction or suspended, as of September 30, 2025, three (0.7 percent) had a completed system impact study, 118 (27.7 percent) had a completed facilities study and 339 (73.7 percent) had a completed construction service agreement.

Table 12-23 Project serial queue times by milestone (days): September 30, 2025

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	0	0.0%	0	0
Feasibility Study	0	0.0%	0	0
System Impact Study	3	0.7%	2,035	2,244
Facilities Study	118	25.7%	2,074	2,563
Construction Service Agreement (CSA) or beyond	339	73.7%	2,542	4,060
Total	460	100.0%		

Table 12-24 shows the time spent in the serial queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the serial queue to the time the project goes in service has generally been decreasing compared to the period prior to 2017 although there are significant exceptions. For example, for a battery project entering the serial queue in 2015, there was an average of 2,062 days from the time it entered the queue until it went in service, compared to 1,409 days when entering the queue in 2018.

66 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Table 12-24 Average time in serial queue (days) by fuel type and year submitted (In Service Projects): September 30, 2025[67]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Battery	983	609	417	710	789	2,062	941		1,409	972	1,084					
CC	1,310	1,426	1,663	1,419	1,175	1,138	1,199	1,013	1,140	1,069	659					
CT - Natural Gas	1,131	804	953	1,073	1,409	619	1,566	1,192	938	317	805					
CT - Oil	717		259							280	349					
CT - Other	729	634	954	1,248	718	360										
Fuel Cell						827				280						
Hydro - Pumped Storage						1,402										
Hydro - Run of River			1,325	614	332		580	426	606							
Nuclear	885	866		1,234			2,434	1,113	1,772							
RICE - Natural Gas			1,702	1,053	1,332	798		250		770						
RICE - Oil						1,849										
RICE - Other	638	1,385	1,479	241	627	622	491		466							
Solar	1,701	1,395	969	1,014	1,003	1,831	1,938	2,019	1,707	1,500	1,135					
Solar + Storage						635	322		553	2,162	809					
Solar + Wind																
Steam - Coal	745		513	1,010	583	853	684	647	1,810	2,139						
Steam - Natural Gas				1,182		421	751				1,286					
Steam - Oil																
Steam - Other	256	838	643													
WInd	2,748	2,711	1,750	2,103	1,205	1,463	1,620	1,398	1,289		997					
Wind + Storage							2,680									

67 A blank cell in this table means that no project of that fuel type, which was submitted to the queue in that year, subsequently went in service.

Table 12-25 shows 609,132.6 MW have entered PJM generation serial queues from January 1, 1997, through June 10, 2023. Table 12-25 presents totals by fuel type and projected in service date as of September 30, 2025. Of the 609,132.6 MW to enter the serial queue, 348,159.4 MW (57.2 percent) were thermal units.

Table 12-25 Total (MW Energy) by unit type and projected in service year: September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,911.0	0.0	0.0	0.0	0.0	0.0	5,686.0
1998	0.0	4,659.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,662.1
1999	0.0	22,573.7	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	20.4	0.0	22,603.2
2000	0.0	9,900.8	409.6	0.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	10,335.3
2001	0.0	7,088.5	432.0	315.0	29.0	0.0	0.0	0.0	165.0	0.0	0.0	0.0	0.0	0.0	0.0	110.6	2.5	0.0	0.0	0.0	0.0	8,142.6
2002	0.0	2,622.2	2,442.0	6.5	0.0	0.0	0.0	107.0	60.0	0.0	0.0	2.9	0.0	0.0	0.0	42.0	10.0	0.0	0.0	65.5	0.0	5,358.1
2003	0.0	4,072.1	638.7	0.0	59.4	0.0	0.0	198.0	46.0	0.0	0.0	17.2	0.0	0.0	0.0	2.0	0.0	0.0	0.0	263.6	0.0	5,297.0
2004	0.0	14,918.2	77.3	33.0	16.1	0.0	0.0	41.0	0.0	8.0	23.3	0.0	0.0	0.0	0.0	42.0	0.0	0.0	0.0	75.0	0.0	15,233.9
2005	0.0	17,149.1	993.0	251.0	42.1	0.0	0.0	0.0	1,693.0	29.0	5.0	7.5	0.0	0.0	0.0	1,880.0	0.0	0.0	0.0	809.9	0.0	22,859.6
2006	0.0	6,033.0	23.3	49.5	43.4	0.0	0.0	147.2	0.0	2.0	30.5	58.5	0.0	0.0	0.0	527.0	0.0	0.0	529.0	1,480.2	0.0	8,923.6
2007	0.0	3,484.6	131.0	17.0	84.0	0.0	0.0	2.5	174.0	19.5	0.0	86.6	0.0	0.0	0.0	750.0	5.0	0.0	68.0	1,087.8	0.0	5,910.0
2008	1.0	7,003.4	628.0	59.3	38.4	0.0	0.0	2.9	331.0	0.0	0.0	57.6	3.3	0.0	0.0	254.5	101.0	0.0	20.0	2,103.2	0.0	10,603.6
2009	120.0	2,717.2	257.7	108.6	118.7	0.0	340.0	252.5	0.0	0.0	0.0	41.2	28.7	0.0	0.0	1,058.0	40.0	0.0	6.0	4,351.5	0.0	9,440.2
2010	16.0	1,912.9	137.8	83.9	320.7	0.0	16.0	94.9	301.0	10.5	0.0	15.8	231.4	0.0	0.0	5,599.0	0.0	0.0	80.8	9,286.1	0.0	18,106.8
2011	52.5	10,887.5	816.4	23.0	110.0	0.0	0.0	27.0	512.0	0.0	16.0	41.8	1,818.5	0.0	0.0	9,614.0	5.5	0.0	108.9	5,355.2	0.0	29,388.2
2012	27.0	13,786.8	389.5	310.0	121.3	0.0	0.0	82.9	391.0	0.0	6.4	2.0	1,892.3	0.0	0.0	3,407.0	0.0	0.0	426.6	7,689.5	0.0	28,532.2
2013	73.0	9,252.2	62.5	730.5	78.9	0.0	0.0	219.0	238.0	0.0	10.0	113.0	674.9	0.0	0.0	1,949.0	44.0	0.0	254.1	8,057.4	0.0	21,756.5
2014	159.1	7,105.5	0.0	684.0	96.0	0.0	0.0	1,120.0	74.0	0.0	0.0	13.3	904.5	0.0	0.0	3,288.0	0.0	0.0	63.8	11,758.7	186.0	25,452.9
2015	214.6	15,591.3	417.4	42.0	21.9	0.0	0.0	378.5	147.8	19.5	9.0	3.8	1,240.1	0.0	0.0	1,271.5	0.0	0.0	81.5	4,161.6	0.0	23,600.4
2016	422.5	16,553.3	332.1	0.0	144.9	2.8	0.0	71.2	4,082.0	46.9	0.0	30.2	1,737.6	3.4	0.0	50.0	40.0	0.0	107.8	4,459.3	0.0	28,083.9
2017	134.1	17,489.5	835.0	401.0	135.0	2.0	0.0	86.2	1,640.0	283.6	0.0	18.2	2,158.3	0.0	0.0	47.0	606.5	0.0	7.2	3,010.2	0.0	26,853.7
2018	175.0	17,902.0	404.9	0.0	11.6	1.1	34.0	12.5	1,644.0	95.0	0.0	41.0	3,369.9	0.6	0.0	148.0	57.0	0.0	0.0	5,135.7	0.0	29,032.3
2019	303.0	14,752.4	1,036.8	14.0	0.0	0.0	0.0	20.5	0.0	79.7	0.0	33.6	7,203.3	629.8	0.0	1,710.0	0.0	0.0	16.0	5,377.6	16.3	31,192.9
2020	621.7	7,243.7	1,173.0	0.0	0.0	2.1	0.0	2.4	128.0	39.9	4.0	0.8	5,726.6	615.5	0.0	20.0	64.0	0.0	0.0	8,886.7	0.0	24,528.4
2021	1,176.9	17,904.2	687.3	4.0	0.0	0.0	0.0	48.0	0.0	15.7	0.0	0.0	13,387.0	2,052.0	0.0	47.0	6.0	0.0	62.5	4,818.0	90.0	40,298.5
2022	2,677.1	12,723.2	1,629.3	0.0	0.0	0.0	1,000.0	28.0	0.0	20.0	0.0	0.0	10,837.9	1,578.3	0.0	0.0	0.0	0.0	0.0	2,249.7	0.0	32,743.4
2023	2,463.2	12,105.0	1,439.7	13.0	0.0	3.0	0.0	36.6	54.2	0.0	0.0	0.0	12,507.8	5,400.9	0.0	0.0	0.0	0.0	0.0	1,987.4	0.0	36,010.8
2024	619.5	4,522.5	646.0	0.0	0.0	0.0	0.0	12.0	1,594.0	0.0	0.0	0.0	7,669.4	1,041.1	0.0	0.0	5.0	0.0	0.0	4,228.2	0.0	20,337.7
2025	263.4	187.7	463.0	0.0	0.0	0.0	0.0	16.8	0.0	0.0	0.0	0.0	5,747.7	292.5	0.0	29.0	0.0	0.0	0.0	4,009.6	0.0	11,009.6
2026	711.0	2,785.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,058.7	262.5	0.0	0.0	0.0	0.0	0.0	4,061.6	0.0	15,878.8
2027	783.2	1,826.1	735.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	7,618.2	392.1	0.0	0.0	0.0	0.0	0.0	1,961.1	0.0	13,515.7
2028	989.0	50.0	19.3	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	5,494.7	1,237.0	0.0	0.0	0.0	0.0	0.0	263.3	0.0	8,104.3
2029	810.0	595.0	599.0	0.0	0.0	0.0	0.0	9.5	0.0	0.0	0.0	0.0	2,343.9	450.0	0.0	0.0	0.0	0.0	0.0	2,509.7	0.0	7,317.1
2030	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,350.0
2031	0.0	0.0	439.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	394.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	983.4
Total	13,062.6	288,172.5	18,298.1	3,145.3	1,478.2	10.9	1,590.0	3,068.0	13,275.0	669.3	104.2	586.2	101,904.8	14,349.6	0.0	36,783.6	986.5	0.0	1,832.2	109,523.4	292.3	609,132.6

Table 12-26 shows there were 43,634.4 MW in the serial queue in the status of active, under construction and suspended as of September 30, 2025. Table 12-26 presents totals by fuel type and projected in service date. Of the 43,634.4 MW, 5,312.5 MW (12.2 percent) are thermal units. Of the 43,634.4 MW with projected in service dates between 2025 and 2031, 5,276.5 MW (12.1 percent) are thermal units.

Table 12-26 Total (MW Energy) by unit type and projected in service year (active, under construction and suspended): September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1998	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1999	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	80.0	0.0	116.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	871.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	871.8
2024	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	769.5	6.6	0.0	0.0	0.0	0.0	0.0	80.0	0.0	896.1
2025	137.9	102.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,763.8	17.5	0.0	0.0	0.0	0.0	0.0	589.0	0.0	4,610.8
2026	671.0	2,210.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,051.5	230.0	0.0	0.0	0.0	0.0	0.0	3,176.4	0.0	13,338.9
2027	672.2	1,201.1	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,758.8	352.1	0.0	0.0	0.0	0.0	0.0	1,161.0	0.0	10,205.2
2028	865.0	50.0	19.3	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	4,489.7	1,072.0	0.0	0.0	0.0	0.0	0.0	263.3	0.0	6,810.3
2029	790.0	595.0	599.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,843.9	450.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	4,477.9
2030	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,030.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,280.0
2031	0.0	0.0	439.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	394.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	983.4
Total	3,426.1	4,158.8	1,117.7	0.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	26,729.0	2,522.2	0.0	36.0	0.0	0.0	0.0	5,549.7	0.0	43,634.4

Table 12-27 shows there were 471,723.5 MW withdrawn from the serial queue from January 1, 1997, through September 30, 2025. Table 12-27 presents totals by fuel type and projected in service date. Of the 471,723.5 MW withdrawn from the serial queue, 280,279.1 MW (59.4 percent) were thermal units. Of the 14,457.3 MW withdrawn with projected in service dates between 2025 and 2031, 2,423.0 MW (16.8 percent) were thermal units.

Table 12-27 Total (MW Energy) by unit type and projected in service year (withdrawn): September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,911.0	0.0	0.0	0.0	0.0	0.0	5,686.0
1998	0.0	4,659.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,662.1
1999	0.0	22,573.7	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22,575.8
2000	0.0	9,900.8	0.0	0.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,904.5
2001	0.0	6,988.5	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.6	0.0	0.0	0.0	0.0	0.0	7,045.1
2002	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	28.0	0.0	0.0	0.0	50.5	0.0	137.7
2003	0.0	1,287.1	0.0	0.0	59.4	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	73.6	0.0	1,422.1
2004	0.0	12,073.2	0.0	0.0	12.0	0.0	0.0	41.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	12,201.2
2005	0.0	17,134.0	0.0	1.0	42.1	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	802.4	0.0	19,844.5
2006	0.0	4,847.0	0.0	0.0	43.4	0.0	0.0	142.0	0.0	0.0	30.5	0.0	0.0	0.0	0.0	520.0	0.0	0.0	0.0	1,430.2	0.0	7,013.1
2007	0.0	3,455.0	0.0	0.0	71.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	675.0	0.0	0.0	50.0	554.5	0.0	4,805.6
2008	1.0	6,826.0	0.0	0.0	38.4	0.0	0.0	2.9	18.0	0.0	0.0	0.0	0.0	0.0	0.0	152.0	0.0	0.0	0.0	1,857.0	0.0	8,895.3
2009	120.0	2,618.2	0.0	61.0	113.7	0.0	0.0	252.0	0.0	0.0	0.0	0.0	28.7	0.0	0.0	935.0	0.0	0.0	6.0	3,129.5	0.0	7,264.1
2010	16.0	1,776.9	0.0	81.0	302.5	0.0	0.0	54.9	0.0	0.0	0.0	0.0	168.5	0.0	0.0	5,512.0	0.0	0.0	20.8	7,853.1	0.0	15,785.7
2011	25.1	8,985.5	0.0	0.0	98.6	0.0	0.0	0.0	140.0	0.0	16.0	0.0	1,747.5	0.0	0.0	8,817.0	0.0	0.0	108.0	4,781.0	0.0	24,718.7
2012	20.5	13,711.5	0.5	310.0	87.7	0.0	0.0	82.9	0.0	0.0	6.4	0.0	1,801.8	0.0	0.0	2,751.0	0.0	0.0	426.6	6,535.0	0.0	25,733.9
2013	72.0	9,168.0	0.0	730.0	38.6	0.0	0.0	79.0	34.0	0.0	10.0	0.0	651.0	0.0	0.0	1,861.0	0.0	0.0	254.1	7,686.3	0.0	20,584.1
2014	114.1	6,438.0	0.0	684.0	96.0	0.0	0.0	1,085.1	74.0	0.0	0.0	0.0	809.7	0.0	0.0	3,212.0	0.0	0.0	10.0	11,308.7	0.0	23,831.6
2015	111.6	13,216.5	12.5	42.0	10.7	0.0	0.0	218.0	0.0	0.6	9.0	0.0	1,041.4	0.0	0.0	1,251.0	0.0	0.0	81.5	3,956.6	0.0	19,951.4
2016	400.1	9,812.3	35.4	0.0	144.0	2.0	0.0	71.2	3,980.0	26.0	0.0	11.7	1,484.8	0.0	0.0	50.0	0.0	0.0	107.8	4,181.8	0.0	20,307.1
2017	134.1	13,041.4	696.0	401.0	135.0	1.3	0.0	15.0	1,640.0	263.7	0.0	17.1	1,822.2	0.0	0.0	0.0	0.0	0.0	7.2	2,375.2	0.0	20,549.1
2018	109.5	10,224.0	64.9	0.0	11.6	1.1	0.0	0.0	1,600.0	89.8	0.0	36.2	3,017.5	0.0	0.0	80.0	27.0	0.0	0.0	4,618.0	0.0	19,879.6
2019	303.0	10,771.9	922.8	14.0	0.0	0.0	0.0	15.0	0.0	39.9	0.0	33.6	6,771.8	629.8	0.0	1,710.0	0.0	0.0	16.0	4,286.6	16.3	25,530.6
2020	621.7	5,987.7	1,022.0	0.0	0.0	2.1	0.0	0.0	100.0	39.9	0.0	0.0	4,789.8	614.4	0.0	20.0	0.0	0.0	0.0	7,786.4	0.0	20,984.0
2021	1,175.4	14,345.5	330.3	0.0	0.0	0.0	0.0	48.0	0.0	1.3	0.0	0.0	12,267.5	2,048.8	0.0	0.0	6.0	0.0	0.0	4,178.0	90.0	34,490.8
2022	2,650.3	8,412.3	1,533.8	0.0	0.0	0.0	1,000.0	28.0	0.0	20.0	0.0	0.0	9,412.3	1,578.3	0.0	0.0	0.0	0.0	0.0	2,249.7	0.0	26,884.7
2023	2,408.2	10,861.0	851.5	0.0	0.0	0.0	0.0	36.6	0.0	0.0	0.0	0.0	9,193.0	5,383.9	0.0	0.0	0.0	0.0	0.0	1,705.0	0.0	30,439.2
2024	577.0	4,522.5	646.0	0.0	0.0	0.0	0.0	12.0	1,594.0	0.0	0.0	0.0	3,705.5	1,034.5	0.0	0.0	0.0	0.0	0.0	4,047.4	0.0	16,138.9
2025	105.5	85.0	463.0	0.0	0.0	0.0	0.0	16.8	0.0	0.0	0.0	0.0	451.7	125.0	0.0	0.0	0.0	0.0	0.0	3,176.7	0.0	4,423.7
2026	40.0	575.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,007.1	32.5	0.0	0.0	0.0	0.0	0.0	885.2	0.0	2,539.8
2027	111.0	625.0	675.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	839.5	40.0	0.0	0.0	0.0	0.0	0.0	800.1	0.0	3,290.6
2028	124.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,005.0	165.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,294.0
2029	20.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	0.0	0.0	0.0	0.0	500.0	0.0	0.0	0.0	0.0	0.0	0.0	2,309.7	0.0	2,839.2
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	9,260.0	235,711.6	7,255.8	2,324.0	1,316.7	6.4	1,200.0	2,209.9	9,227.0	481.2	76.9	98.6	62,586.5	11,652.2	0.0	34,396.6	33.0	0.0	1,088.0	92,692.9	106.3	471,723.5

Completion Rates

The probability of a project going into service increases as each step of the serial planning process is completed. Table 12-28 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and any milestone completed beyond the FSA including a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA) and Wholesale Market Participant Agreement (WMPA) as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone.[68] For each unit type, the total MW in service was divided by the total energy MW entered in the serial queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all battery projects to ever enter the serial queue and complete the system impact study stage, 6.7 percent of the queued MW have gone into service. The completion rate for battery projects increases to 17.9 percent when battery projects complete the facility study agreement and further increases to 37.3 percent when battery projects complete the construction service agreement. Of all battery projects to enter the serial queue, only 3.0 percent of the queued MW have gone into service.

Table 12-28 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: September 30, 2025

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	6.7%	17.9%	37.3%	3.0%
CC	33.9%	49.6%	71.4%	16.6%
CT - Natural Gas	59.3%	70.4%	72.1%	50.0%
CT - Oil	35.7%	60.0%	90.9%	25.4%
CT - Other	12.1%	18.4%	29.5%	10.6%
Fuel Cell	50.6%	51.8%	51.8%	41.4%
Hydro - Pumped Storage	35.8%	35.8%	66.1%	24.5%
Hydro - Run of River	40.2%	55.5%	61.5%	20.7%
Nuclear	34.7%	41.9%	51.3%	28.5%
RICE - Natural Gas	32.4%	44.7%	49.4%	28.0%
RICE - Oil	34.0%	59.7%	59.7%	26.2%
RICE - Other	88.9%	91.3%	92.0%	77.9%
Solar	27.6%	44.9%	62.4%	13.4%
Solar + Storage	3.5%	9.4%	35.2%	1.2%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.8%	25.7%	37.9%	6.4%
Steam - Natural Gas	90.5%	91.1%	91.1%	90.5%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	31.0%	40.6%	48.6%	28.0%
Wind	16.6%	32.2%	49.4%	10.1%
Wind + Storage	45.3%	45.3%	45.3%	45.3%

On September 30, 2025, 43,634.4 MW were in generation request serial queues in the status of active, under construction or suspended. Of the total 43,634.4 MW in the queue, 31,841.9 MW (72.9 percent) have reached the CSA milestone and 11,792.5 MW (27.1 percent) have not received a completed CSA. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or any milestone beyond the FSA, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 23,288.8 MW (53.3 percent) of new generation in the serial queue are expected to go into service.

Table 12-29 shows the percent of all project MW, by unit type, to go in service by year submitted to the serial queue. Of all battery projects that entered the

68 All milestones after the FSA are included in the totals under the CSA headings of the tables within Section 12, "Generation and Transmission Planning."

serial queue in 2010, 65.5 percent reached the status of in service by September 30, 2025. Of all battery projects that entered the serial queue in 2016, only 1.3 percent have reached the status of in service as of September 30, 2025.

Table 12-29 Percent of all projects (MW energy) to go in service by unit type and year submitted to the serial queue: September 30, 2025

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Battery	65.5%	8.3%	15.1%	45.7%	21.5%	11.5%	1.3%	0.0%	3.1%	0.5%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	13.4%	20.7%	8.1%	4.1%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CT - Natural Gas	100.0%	98.3%	71.6%	42.2%	56.8%	0.2%	13.2%	38.9%	8.4%	5.4%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%
CT - Oil	100.0%	NA	1.2%	0.0%	0.0%	NA	NA	NA	0.0%	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CT - Other	28.8%	26.2%	36.1%	100.0%	0.0%	100.0%	NA	0.0%	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel Cell	NA	NA	NA	NA	NA	67.4%	0.0%	0.0%	NA	100.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro - Pumped Storage	NA	NA	NA	NA	NA	100.0%	NA	NA	0.0%	0.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	NA	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	15.5%	1.6%	0.0%	100.0%	NA	NA	25.4%	100.0%	100.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RICE - Natural Gas	NA	NA	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	NA	100.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%
RICE - Oil	0.0%	0.0%	NA	NA	NA	30.8%	NA	NA	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	10.7%	8.1%	16.9%	24.4%	32.7%	29.9%	38.8%	15.1%	6.6%	8.8%	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Storage	NA	NA	NA	NA	NA	100.0%	0.7%	0.0%	0.0%	3.2%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	59.2%	100.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Natural Gas	NA	NA	NA	100.0%	0.0%	100.0%	100.0%	100.0%	NA	NA	45.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	NA	NA	NA	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
WInd	6.1%	3.4%	2.5%	20.9%	20.7%	12.5%	21.0%	2.6%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
All	11.6%	19.0%	25.9%	35.9%	42.5%	15.7%	26.4%	11.7%	4.0%	5.7%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%

Table 12-30 shows the total MW that went in service each year, by unit type, since 1999. In the first nine months of 2025, 2,117.1 MW from the serial queue went in service. Of the 2,117.1 MW that went in service, 1,883.2 MW (89.0 percent) were solar units, 150 MW (7.1 percent) were solar + storage units, 54.9 MW (2.6 percent) were wind units and 29.0 MW (1.4 percent) were coal fired steam units.

Table 12-30 Total (MW Energy) by unit type and year project went in service: September 30, 2025

Unit Type	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Battery	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	4.5	23.0	24.0	110.4	10.0	2.0	40.0	25.5	0.0	1.5	0.0	61.8	42.5	0.0
CC	0.0	0.0	100.0	2,608.0	2,785.0	2,845.0	15.1	1,196.0	4.0	177.0	52.0	136.0	1,869.0	162.7	82.2	2,155.7	2,977.7	5,418.0	3,888.1	10,865.0	2,983.0	88.0	3,424.7	1,825.9	2,644.0	0.0	0.0
CT - Natural Gas	0.0	409.6	432.0	2,442.0	638.7	61.3	993.0	39.3	97.0	821.0	181.7	97.8	850.4	393.0	95.0	125.2	317.9	72.0	212.0	388.0	104.0	156.0	314.0	151.6	532.1	0.0	0.0
CT - Oil	4.0	0.0	315.0	6.5	0.0	33.0	292.0	7.5	21.0	15.3	85.6	0.0	23.9	2.0	0.5	2.0	0.0	0.0	0.0	0.0	0.0	13.0	0.0	0.0	0.0	0.0	0.0
CT - Other	0.0	0.0	10.0	0.0	0.0	4.1	0.0	0.0	11.0	6.9	0.0	18.2	0.0	70.7	17.6	6.0	8.0	5.9	0.0	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	0.0	3.0	0.0	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0	107.0	196.0	2.0	0.0	5.7	2.5	0.0	54.2	180.0	27.0	0.0	6.0	28.9	160.5	0.0	29.5	5.5	0.0	2.4	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	165.0	15.0	44.0	0.0	1,693.0	242.0	130.0	115.0	0.0	281.0	422.0	328.0	117.0	80.0	54.0	133.8	130.0	0.0	0.0	0.0	0.0	0.0	54.2	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0	8.0	29.0	2.0	19.5	0.0	0.0	10.5	0.0	0.0	0.0	0.0	18.9	20.9	19.9	5.2	39.8	0.0	14.4	0.0	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0	23.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0	0.0	0.0	0.0
RICE - Other	0.0	1.2	0.0	2.9	17.2	0.0	27.5	44.9	86.6	57.6	38.8	13.8	39.8	2.0	109.0	0.0	3.8	19.3	22.4	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.1	6.8	137.2	98.9	44.4	59.8	172.1	290.8	332.9	284.5	555.6	1,670.8	807.5	1,078.5	1,283.9	3,874.0	1,883.2
Solar + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	1.0	2.0	1.1	0.0	3.2	0.0	17.0	0.0	150.0
Solar + Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Coal	12.0	20.0	59.0	21.0	0.0	37.0	20.0	14.0	55.0	720.5	123.0	177.0	97.0	708.0	48.0	16.0	92.5	0.0	47.0	24.0	20.0	0.0	11.0	0.0	0.0	0.0	29.0
Steam - Natural Gas	0.0	0.0	2.5	10.0	0.0	0.0	0.0	0.0	25.0	145.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	696.5	0.0	0.0	0.0	64.0	0.0	0.0	0.0	5.0	0.0
Steam - Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	529.0	18.0	20.0	0.0	122.5	0.9	0.0	50.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WInd	0.0	0.0	0.0	15.0	190.0	20.4	7.5	380.0	867.3	729.8	622.0	1,183.5	326.6	1,424.5	150.0	500.0	455.0	465.8	700.7	762.0	535.0	1,008.6	310.0	0.0	282.4	289.8	54.9
Wind + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	186.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	20.0	430.8	1,083.5	5,227.4	3,870.9	3,034.1	3,077.1	2,460.4	1,522.9	2,811.4	1,502.4	2,243.1	3,826.6	3,194.2	742.7	3,001.4	4,371.8	7,133.0	5,385.5	12,411.7	4,268.0	3,009.8	4,886.2	3,056.0	4,875.4	4,211.3	2,117.1

Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the serial queue, but not on the size of the project. Table 12-31 shows the number of projects that entered the serial queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). The number of serial queue entries had increased during the past several years, primarily by renewable projects. Of the 2,809 projects entered from January 2015 through June 2023, 2,062 projects (73.4 percent) were renewable.

Table 12-31 Number of projects entered in the serial queue by fuel group: September 30, 2025

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
1997	2	15.38%	0	0.00%	0	0.00%	11	84.62%	0	0.00%	13
1998	0	0.00%	0	0.00%	0	0.00%	18	100.00%	0	0.00%	18
1999	1	1.11%	5	5.56%	0	0.00%	82	91.11%	2	2.22%	90
2000	2	2.41%	3	3.61%	0	0.00%	75	90.36%	3	3.61%	83
2001	4	4.40%	6	6.59%	0	0.00%	78	85.71%	3	3.30%	91
2002	3	5.88%	15	29.41%	0	0.00%	23	45.10%	10	19.61%	51
2003	1	1.89%	34	64.15%	0	0.00%	13	24.53%	5	9.43%	53
2004	4	7.41%	17	31.48%	0	0.00%	23	42.59%	10	18.52%	54
2005	3	2.26%	74	55.64%	1	0.75%	36	27.07%	19	14.29%	133
2006	9	5.73%	67	42.68%	0	0.00%	47	29.94%	34	21.66%	157
2007	9	4.11%	64	29.22%	1	0.46%	123	56.16%	22	10.05%	219
2008	3	1.39%	102	47.22%	7	3.24%	79	36.57%	25	11.57%	216
2009	10	5.78%	107	61.85%	2	1.16%	34	19.65%	20	11.56%	173
2010	5	1.13%	370	83.90%	5	1.13%	40	9.07%	21	4.76%	441
2011	6	1.69%	264	74.37%	4	1.13%	61	17.18%	20	5.63%	355
2012	2	1.26%	59	37.11%	11	6.92%	69	43.40%	18	11.32%	159
2013	1	0.65%	54	35.06%	21	13.64%	69	44.81%	9	5.84%	154
2014	0	0.00%	100	52.08%	21	10.94%	59	30.73%	12	6.25%	192
2015	0	0.00%	130	42.07%	63	20.39%	103	33.33%	13	4.21%	309
2016	2	0.50%	284	71.18%	22	5.51%	65	16.29%	26	6.52%	399
2017	2	0.56%	280	78.87%	7	1.97%	47	13.24%	19	5.35%	355
2018	1	0.23%	336	77.42%	50	11.52%	46	10.60%	1	0.23%	434
2019	0	0.00%	487	78.30%	85	13.67%	49	7.88%	1	0.16%	622
2020	2	0.29%	545	78.99%	122	17.68%	21	3.04%	0	0.00%	690
2021	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
2022	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
2023	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
Total	72	1.32%	3,403	62.31%	422	7.73%	1,271	23.27%	293	5.37%	5,461

As of September 30, 2025, renewable projects make up 85.9 percent of all projects in the serial queue and those projects account for 79.9 percent of the nameplate MW currently active, suspended or under construction.

Table 12-32 Serial queue details by fuel group: September 30, 2025

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	1	0.2%	44.0	0.1%
Renewable	395	85.9%	34,851.8	79.9%
Storage	47	10.2%	3,426.1	7.9%
Thermal	17	3.7%	5,312.5	12.2%
Other	0	0.0%	0.0	0.0%
Total	460	100.0%	43,634.4	100.0%

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue.

Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derated wind resources to 13 percent of nameplate capacity until there was operational data to support a different conclusion.[69] PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent.

Beginning with the 2023/2024 Delivery Year, unforced capacity for intermittent resources and limited duration resources are determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis will determine capacity derates by resource class for each Delivery Year. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. For example, the 2027/2028 Base Residual Auction ELCC class rating for onshore wind resources is 41.0 percent, for solar resources with tracking panels is 8.0 percent and for solar resources with fixed panels is 7.0 percent.[70] The ELCC class rating for battery or energy storage resources replaces the 10 hour rule that was previously used to determine the unforced capacity value for an energy storage resource. PJM defined four different energy storage classes differentiated by duration. The ELCC class rating is 58.0 percent for storage resources that can continuously generate energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 67.0 percent for six hour storage and 70.0 percent for eight hour storage and 78.0 percent for 10 hour storage.[71]

While renewables currently make up the majority of both projects and nameplate MW in the serial queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables. Table 12-33 shows the total MW of all projects in the serial queue as of September 30, 2025, in the status of active, suspended and under construction, by unit type. Table 12-33 also shows the total MW Energy and MW Capacity for each fuel type adjusted based on current historical completion rates and, for Capacity MW in the queue, adjusted for ELCC derates.[72]

Table 12-33 shows that of the 4,158.8 MW, on an energy basis, of combined cycle projects in the serial queue, 2,958.5 MW (71.1 percent) are expected to go in service based on historical completion rates as of September 30, 2025.

Of the 3,426.1 MW, on an energy basis, of battery projects in the serial queue, 931.2 MW (27.2 percent) are expected to go in service based on historical completion rates as of September 30, 2025.

Of the 34,851.8 MW, on an energy basis, of renewable projects in the serial queue, 18,564.5 MW (53.3 percent) are expected to go in service based on historical completion rates as of September 30, 2025.

Of the 3,949.1 MW, on a capacity basis that requested CIRs, of combined cycle projects requested in the generation serial queues in the status of active, under construction or suspended, 2,777.1 MW (70.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 3,949.1 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,055.1 MW of capacity (52.0 percent of the total requested capacity).

69 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).
70 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2027/2028 Base Residual Auction*, PJM Interconnection L.L.C. (August 1, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf>
71 Additional information available in *PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, PJM Interconnection L.L.C., Rev. 5 (June 27, 2024).
72 Unless otherwise noted, the ELCC derate adjusted MW are calculated using the 2027/2028 Base Residual Auction ELCC factors. The adjusted MW are calculated using the four hour storage ELCC derate of 58.0 percent for battery resources, 41.0 percent ELCC derate for wind resources and 8.0 percent ELCC derate for solar resources.

Of the 2,232.3 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation serial queues in the status of active, under construction or suspended, 161.5 MW (7.2 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 2,232.3 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 93.7 MW of capacity (4.2 percent of the total requested capacity).

Of the 18,186.8 MW, on a capacity basis that requested CIRs, of renewable projects requested in the generation serial queues in the status of active, under construction or suspended, 9,797.0 MW (53.9 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 18,186.8 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 965.8 MW of capacity (5.3 percent of the total requested capacity).

As of September 30, 2025, 25,603.7 MW of capacity requests (requested CIRs) were in the generation serial queues in the status of active, under construction or suspended. Based on historical completion rates, 13,565.8 MW (53.0 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 25,603.7 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 3,631.5 MW of capacity (14.2 percent of the total requested capacity).

Table 12-33 Serial queue totals for projects (active, suspended and under construction) by unit type adjusted for current historical completion rates and ELCC derates (MW): September 30, 2025

	Energy (MW)		Capacity (MW)		
Unit Type	Total	Completion Rate Adjusted	Total	Completion Rate Adjusted	Completion Rate and ELCC Adjusted
Battery	3,426.1	931.2	2,232.3	161.5	93.7
CC	4,158.8	2,958.5	3,949.1	2,777.1	2,055.1
CT - Natural Gas	1,117.7	798.4	1,155.5	794.4	484.6
CT - Oil	0.0	0.0	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0
Hydro - Run of River	51.0	28.3	30.0	17.2	6.7
Nuclear	44.0	22.6	44.0	22.1	21.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0	0.0	0.0
Solar	26,729.0	15,250.4	15,262.3	8,773.0	701.8
Solar + Storage	2,522.2	591.7	1,817.5	471.2	37.7
Solar + Wind	0.0	0.0	0.0	0.0	0.0
Steam - Coal	36.0	13.6	36.0	13.7	11.4
Steam - Natural Gas	0.0	0.0	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0
Wind	5,549.7	2,694.1	1,076.9	535.6	219.6
Wind + Storage	0.0	0.0	0.0	0.0	0.0
Total	43,634.4	23,288.8	25,603.7	13,565.8	3,631.5

Analysis by Unit Type and Project Classification

Table 12-34 shows the status of all generation serial queue projects by unit type and project classification as of September 30, 2025. As of September 30, 2025, 5,461 projects, representing 609,132.6 MW, have entered the serial queue process from 1997 until the implementation of the new cycle process on July 10, 2023. Of those, 1,267 projects, representing 93,774.7 MW (15.4 percent of the MW), went into service. Of the projects that entered the serial queue process, 3,734 projects, representing 471,232.5 MW (77.4 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

A total of 4,354 projects have been classified as new generation and 1,107 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 4,361 projects (79.9 percent) of all 5,461 generation serial queue projects to enter the queue since January 1, 1997.

Table 12-34 Status of all generation serial queue projects: September 30, 2025

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	32	67	50	10	25	2	0	10	2	11	0	55	308	7	0	8	6	0	4	99	1	697
	Upgrade	8	117	137	25	5	1	3	19	45	9	2	16	84	1	0	59	10	0	8	20	1	570
Under Construction	New Generation	4	2	0	0	0	0	0	0	0	0	0	0	60	1	0	0	0	0	0	8	0	75
	Upgrade	1	2	1	0	0	0	0	0	1	0	0	0	15	1	0	1	0	0	0	2	0	24
Suspended	New Generation	7	1	0	0	0	0	0	0	0	0	0	0	77	1	0	0	0	0	0	7	0	93
	Upgrade	3	0	0	0	0	0	0	0	0	0	0	0	13	0	0	0	0	0	0	2	0	18
Withdrawn	New Generation	236	440	32	10	82	28	4	48	9	29	12	16	1,629	146	0	55	1	0	34	487	1	3,299
	Upgrade	92	107	25	13	12	0	0	4	15	0	2	3	106	5	0	15	2	0	2	31	1	435
Active	New Generation	24	3	1	0	0	0	0	0	0	0	0	0	131	25	0	0	0	0	0	6	0	190
	Upgrade	8	1	5	0	0	0	0	1	0	0	0	0	42	1	0	0	0	0	0	2	0	60
Total Projects	New Generation	303	513	83	20	107	30	4	58	11	40	12	71	2,205	180	0	63	7	0	38	607	2	4,354
	Upgrade	112	227	168	38	17	1	3	24	61	9	4	19	260	8	0	75	12	0	10	57	2	1,107

Table 12-35 shows the totals in Table 12-34 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 79.2 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 16.7 percent of hydro run of river upgrades were withdrawn and 4.2 percent of hydro run of river upgrades are active in the serial queue.

Table 12-35 Status of all generation serial queue projects as a percent of total projects by classification: September 30, 2025

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	10.6%	13.1%	60.2%	50.0%	23.4%	6.7%	0.0%	17.2%	18.2%	27.5%	0.0%	77.5%	14.0%	3.9%	0.0%	12.7%	85.7%	0.0%	10.5%	16.3%	50.0%	16.0%
	Upgrade	7.1%	51.5%	81.5%	65.8%	29.4%	100.0%	100.0%	79.2%	73.8%	100.0%	50.0%	84.2%	32.3%	12.5%	0.0%	78.7%	83.3%	0.0%	80.0%	35.1%	50.0%	51.5%
Under Construction	New Generation	1.3%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	1.7%
	Upgrade	0.9%	0.9%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	5.8%	12.5%	0.0%	1.3%	0.0%	0.0%	0.0%	3.5%	0.0%	2.2%
Suspended	New Generation	2.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	0.0%	2.1%
	Upgrade	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	0.0%	1.6%
Withdrawn	New Generation	77.9%	85.8%	38.6%	50.0%	76.6%	93.3%	100.0%	82.8%	81.8%	72.5%	100.0%	22.5%	73.9%	81.1%	0.0%	87.3%	14.3%	0.0%	89.5%	80.2%	50.0%	75.8%
	Upgrade	82.1%	47.1%	14.9%	34.2%	70.6%	0.0%	0.0%	16.7%	24.6%	0.0%	50.0%	15.8%	40.8%	62.5%	0.0%	20.0%	16.7%	0.0%	20.0%	54.4%	50.0%	39.3%
Active	New Generation	7.9%	0.6%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%	13.9%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	4.4%
	Upgrade	7.1%	0.4%	3.0%	0.0%	0.0%	0.0%	0.0%	4.2%	0.0%	0.0%	0.0%	0.0%	16.2%	12.5%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	0.0%	5.4%

Table 12-36 shows the total MW of projects in the PJM generation status queue by unit type and project classification. For example, the 487 new generation wind projects that have been withdrawn from the serial queue as of September 30, 2025, (as shown in Table 12-34) constitute 90,541.2 MW. The 440 new generation combined cycle projects that have been withdrawn in the same time period constitute 221,887.8 MW.

Table 12-36 Status of all generation (MW) in the generation serial queue: September 30, 2025

Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
		Project MW																					
In Service	New Generation	324.2	39,701.9	6,734.4	676.5	149.2	1.5	0.0	371.5	1,639.0	170.8	0.0	440.1	11,204.7	172.1	0.0	1,343.0	728.0	0.0	60.9	10,688.3	186.0	74,592.1
	Upgrade	52.4	8,600.1	3,190.2	144.8	12.3	3.0	390.0	435.6	2,365.0	17.3	27.3	47.5	1,384.6	3.2	0.0	1,008.0	225.5	0.0	683.3	592.5	0.0	19,182.6
Under Construction	New Generation	355.7	1,515.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,644.2	3.9	0.0	0.0	0.0	0.0	0.0	1,808.4	0.0	10,327.2
	Upgrade	50.0	153.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	504.7	100.0	0.0	36.0	0.0	0.0	0.0	118.5	0.0	1,067.0
Suspended	New Generation	482.0	1,270.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,488.5	150.0	0.0	0.0	0.0	0.0	0.0	1,954.5	0.0	9,345.0
	Upgrade	102.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	319.0	0.0	0.0	0.0	0.0	0.0	0.0	107.3	0.0	528.5
Withdrawn	New Generation	7,063.0	221,887.8	5,794.3	1,735.0	1,248.0	6.4	1,200.0	2,105.9	8,161.0	481.2	63.9	88.6	59,601.3	11,208.5	0.0	33,511.6	27.0	0.0	1,050.9	90,541.2	90.0	445,865.5
	Upgrade	2,196.9	13,823.9	1,461.5	589.0	68.7	0.0	0.0	104.0	1,066.0	0.0	13.0	10.0	2,985.2	443.7	0.0	885.0	6.0	0.0	37.1	2,151.8	16.3	25,858.0
Active	New Generation	2,114.0	1,175.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,620.4	2,174.3	0.0	0.0	0.0	0.0	0.0	1,411.0	0.0	19,063.6
	Upgrade	322.2	45.0	488.7	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	2,152.3	94.0	0.0	0.0	0.0	0.0	0.0	150.0	0.0	3,303.2
Total Projects	New Generation	10,338.9	265,549.7	13,097.7	2,411.5	1,397.2	7.9	1,200.0	2,477.4	9,800.0	652.0	63.9	528.7	94,559.0	13,708.7	0.0	34,854.6	755.0	0.0	1,111.8	106,403.3	276.0	559,193.3
	Upgrade	2,723.7	22,622.8	5,200.4	733.8	81.0	3.0	390.0	590.6	3,475.0	17.3	40.3	57.5	7,345.8	640.9	0.0	1,929.0	231.5	0.0	720.4	3,120.1	16.3	49,939.4

Table 12-37 shows the MW totals in Table 12-36 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 85.1 percent of wind project MW classified as new generation have been withdrawn from the serial queue between January 1, 1997, and September 30, 2025.

Table 12-37 Status of all generation serial queue projects as percent of total MW in project classification: September 30, 2025

Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
		Percent of Total Projects by Classification																					
In Service	New Generation	3.1%	15.0%	51.4%	28.1%	10.7%	19.2%	0.0%	15.0%	16.7%	26.2%	0.0%	83.2%	11.8%	1.3%	0.0%	3.9%	96.4%	0.0%	5.5%	10.0%	67.4%	13.3%
	Upgrade	1.9%	38.0%	61.3%	19.7%	15.2%	100.0%	100.0%	73.8%	68.1%	100.0%	67.7%	82.6%	18.8%	0.5%	0.0%	52.3%	97.4%	0.0%	94.9%	19.0%	0.0%	38.4%
Under Construction	New Generation	3.4%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	0.0%	1.8%
	Upgrade	1.8%	0.7%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	6.9%	15.6%	0.0%	1.9%	0.0%	0.0%	0.0%	3.8%	0.0%	2.1%
Suspended	New Generation	4.7%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.8%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	0.0%	1.7%
	Upgrade	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.4%	0.0%	1.1%
Withdrawn	New Generation	68.3%	83.6%	44.2%	71.9%	89.3%	80.8%	100.0%	85.0%	83.3%	73.8%	100.0%	16.8%	63.0%	81.8%	0.0%	96.1%	3.6%	0.0%	94.5%	85.1%	32.6%	79.7%
	Upgrade	80.7%	61.1%	28.1%	80.3%	84.8%	0.0%	0.0%	17.6%	30.7%	0.0%	32.3%	17.4%	40.6%	69.2%	0.0%	45.9%	2.6%	0.0%	5.1%	69.0%	100.0%	51.8%
Active	New Generation	20.4%	0.4%	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.3%	15.9%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	3.4%
	Upgrade	11.8%	0.2%	9.4%	0.0%	0.0%	0.0%	0.0%	8.6%	0.0%	0.0%	0.0%	0.0%	29.3%	14.7%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	0.0%	6.6%

Table 12-38 shows the project MW that entered the PJM generation serial queue by unit type and year of entry. Since 2016, 82.5 percent of all new projects entering the generation serial queue have been combined cycle (19.6 percent), wind (17.2 percent) or solar projects (45.7 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015 through June 10, 2023, 14,641.9 MW of renewable hybrid units have entered the serial queue.

Table 12-38 Serial queue project MW by unit type and queue entry year: September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,781.0
1999	0.0	29,412.7	2,069.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	32,420.2
2000	0.0	21,144.8	493.6	31.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	0.0	0.0	1,244.6	10.0	0.0	0.0	234.9	0.0	27,377.8
2002	0.0	4,154.0	11.7	0.0	70.5	0.0	0.0	293.0	236.0	8.0	23.3	4.5	0.0	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	0.0	0.0	1,187.0	0.0	0.0	0.0	1,428.7	186.0	8,488.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	0.0	0.0	6,360.0	0.0	0.0	24.0	6,020.0	0.0	20,364.9
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	0.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	0.0	29,964.2
2007	0.0	13,926.6	941.2	215.9	149.5	0.0	16.0	209.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	68.5	18,510.5	0.0	43,733.5
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	0.0	0.0	1,200.5	0.0	0.0	189.8	10,955.5	0.0	41,663.1
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	54.6	3,671.4	0.0	0.0	64.0	0.0	0.0	173.5	9,803.4	0.0	23,886.9
2011	24.1	19,744.0	29.5	0.0	172.5	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,014.0	0.0	0.0	357.0	0.0	0.0	49.0	5,576.4	0.0	28,267.8
2012	142.6	18,014.8	102.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	284.6	0.0	0.0	1,837.0	0.0	0.0	143.1	1,529.8	0.0	22,566.8
2013	217.4	10,493.1	1,201.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	0.0	0.0	158.0	40.0	0.0	44.7	1,296.6	0.0	13,952.1
2014	246.9	11,704.5	1,532.5	401.0	7.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,480.4	0.0	0.0	1,730.5	27.0	0.0	43.1	1,691.3	0.0	18,991.1
2015	546.9	27,550.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,919.3	3.4	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,560.9
2016	111.1	18,802.5	1,392.0	0.0	0.0	2.9	0.0	12.5	59.0	23.5	0.0	38.9	11,538.9	85.6	0.0	80.0	77.0	0.0	0.0	3,445.7	16.3	35,685.9
2017	24.6	5,477.6	691.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,686.8	324.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,660.3
2018	1,413.7	11,080.1	2,510.5	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,815.4	3,868.1	0.0	49.0	0.0	0.0	0.0	17,278.3	0.0	56,760.4
2019	4,192.8	3,332.5	1,003.7	13.0	0.0	3.0	500.0	99.0	0.0	14.4	0.0	0.0	25,252.2	4,757.4	0.0	11.0	0.0	0.0	0.0	6,036.1	0.0	45,215.1
2020	5,915.1	50.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	20,303.8	5,310.2	0.0	0.0	11.0	0.0	0.0	2,096.4	0.0	34,717.4
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	13,062.6	288,172.5	18,298.1	3,145.3	1,478.2	10.9	1,590.0	3,068.0	13,275.0	669.3	104.2	586.2	101,904.8	14,349.6	0.0	36,783.6	986.5	0.0	1,832.2	109,523.4	292.3	609,132.6

Combined Cycle Project Analysis

Table 12-39 shows the status of all combined cycle projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the nine combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, four projects (44.4 percent) are located in the APS Zone.

Table 12-39 Status of all combined cycle serial queue projects by zone (number of projects): September 30, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	7	0	3	4	2	3	0	2	0	7	2	0	7	4	0	5	2	4	9	5	0	67
	Upgrade	3	15	0	10	5	0	6	0	0	0	16	5	0	6	5	0	13	3	4	12	14	0	117
Under Construction	New Generation	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	2
Suspended	New Generation	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	24	20	0	46	14	8	17	1	1	2	18	16	3	26	25	0	44	41	35	42	55	2	440
	Upgrade	7	10	0	11	4	0	4	0	1	0	11	6	0	8	7	0	3	7	5	8	15	0	107
Active	New Generation	0	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
	Upgrade	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Total Projects	New Generation	25	29	0	52	19	10	20	1	3	2	25	18	3	33	29	0	49	43	39	51	60	2	513
	Upgrade	10	25	0	22	9	0	11	0	1	0	27	11	0	14	12	0	16	10	9	20	30	0	227

Table 12-40 shows the status of all combined cycle projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 4,158.8 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,915.0 MW (46.0 percent) are located in the APS Zone.

Table 12-40 Status of all combined cycle serial queue projects by zone (MW): September 30, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	650.0	5,611.0	0.0	1,970.0	3,751.0	140.0	2,960.9	0.0	533.0	0.0	5,828.6	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,892.0	1,698.5	0.0	39,701.9
	Upgrade	229.0	1,300.0	0.0	959.7	344.0	0.0	642.6	0.0	0.0	0.0	1,035.0	102.0	0.0	110.0	188.9	0.0	1,075.5	112.3	228.6	1,426.6	845.9	0.0	8,600.1
Under Construction	New Generation	0.0	575.0	0.0	0.0	940.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,515.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	102.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.1	0.0	153.8
Suspended	New Generation	0.0	0.0	0.0	1,270.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,270.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	8,542.5	13,559.5	0.0	22,373.1	9,596.0	3,122.1	11,392.0	1,150.0	134.5	665.0	12,961.0	5,145.4	991.8	13,562.6	13,001.0	0.0	24,140.0	16,114.0	22,268.2	18,917.7	24,244.6	6.9	221,887.8
	Upgrade	156.9	1,031.0	0.0	1,368.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	1,410.0	0.0	413.0	1,742.0	0.0	240.0	1,125.6	229.1	703.0	2,217.9	0.0	13,823.9
Active	New Generation	0.0	575.0	0.0	600.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,175.0
	Upgrade	0.0	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0
Total Projects	New Generation	9,192.5	20,320.5	0.0	26,213.1	14,287.0	3,262.1	14,352.9	1,150.0	667.5	665.0	18,789.6	5,464.6	991.8	15,228.4	15,558.0	0.0	26,805.0	18,014.0	23,828.2	24,809.7	25,943.1	6.9	265,549.7
	Upgrade	385.9	2,331.0	0.0	2,372.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,815.4	1,512.0	0.0	523.0	1,930.9	0.0	1,315.5	1,237.9	457.7	2,129.6	3,114.9	0.0	22,622.8

Of the nine combined cycle units in the serial queue as of September 30, 2025, in the status of active, under construction or suspended, no units had a projected in service date prior to January 1, 2025 and nine units, representing 4,158.8 MW had a projected in service date between January 1, 2025, and December 31, 2029.

Combustion Turbine – Natural Gas Project Analysis

Table 12-41 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through July 10, 2023, by zone. Of the seven combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, four projects (57.1 percent) are located in the ATSI Zone.

Table 12-41 Status of all combustion turbine – natural gas generation serial queue projects by zone (number of projects): September 30, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	5	0	0	6	0	3	1	0	0	1	3	6	0	2	1	0	2	5	2	4	9	0	50
	Upgrade	4	11	0	10	5	0	20	6	0	0	28	8	0	5	5	0	4	8	5	4	14	0	137
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	2	6	0	0	0	2	1	1	0	0	4	0	1	1	0	0	1	6	0	1	6	0	32
	Upgrade	3	1	0	1	1	0	5	3	0	2	3	0	0	0	1	0	0	2	3	0	0	0	25
Active	New Generation	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
Total Projects	New Generation	7	6	0	6	0	5	2	1	0	1	8	6	1	3	1	0	3	11	2	5	15	0	83
	Upgrade	7	12	0	12	10	0	26	9	0	2	31	8	0	5	6	0	4	10	8	4	14	0	168

Table 12-42 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 1,117.7 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 569.0 MW (50.9 percent) are located in the DOM Zone.

Table 12-42 Status of all combustion turbine – natural gas serial queue projects by zone (MW): September 30, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	360.7	0.0	0.0	1,184.0	0.0	23.0	190.0	0.0	0.0	205.0	1,081.0	1,140.0	0.0	520.0	10.0	0.0	559.0	379.9	5.0	150.9	925.9	0.0	6,734.4
	Upgrade	43.7	278.1	0.0	267.8	105.0	0.0	744.0	83.5	0.0	0.0	925.7	86.0	0.0	20.0	47.6	0.0	42.0	40.5	39.0	252.3	215.0	0.0	3,190.2
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	237.5	1,519.0	0.0	0.0	0.0	153.6	10.0	104.0	0.0	0.0	1,069.8	0.0	73.0	2.1	0.0	0.0	0.5	789.8	0.0	19.9	1,815.1	0.0	5,794.3
	Upgrade	165.5	6.0	0.0	4.0	25.0	0.0	686.2	124.0	0.0	18.5	57.0	0.0	0.0	0.0	0.0	0.0	0.0	327.0	48.3	0.0	0.0	0.0	1,461.5
Active	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0
	Upgrade	0.0	0.0	0.0	30.0	458.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	488.7
Total Projects	New Generation	598.2	1,519.0	0.0	1,184.0	0.0	176.6	200.0	104.0	0.0	205.0	2,719.8	1,140.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	13,097.7
	Upgrade	209.2	284.1	0.0	301.8	588.7	0.0	1,490.2	207.5	0.0	18.5	982.7	86.0	0.0	20.0	47.6	0.0	42.0	367.5	87.3	252.3	215.0	0.0	5,200.4

Of the seven combustion turbine natural gas units in the serial queue as of September 30, 2025, in the status of active, under construction or suspended, no units had a projected in service date prior to January 1, 2025 and seven units, representing 1,117.7 MW had a projected in service date between January 1, 2025, and December 31, 2031.

Wind Project Analysis

Table 12-43 shows the status of all wind generation projects, by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 27 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM serial generation queue, 11 projects (40.7 percent) are located in the COMED Zone.

Table 12-43 Status of all wind generation serial queue projects by zone (number of projects): September 30, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	17	0	18	0	0	28	0	0	0	4	0	0	0	0	0	0	23	0	8	0	0	99
	Upgrade	0	2	0	3	0	0	9	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	20
Under Construction	New Generation	0	2	0	1	0	0	3	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	8
	Upgrade	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Suspended	New Generation	1	1	0	1	0	0	2	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	7
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	23	120	0	46	10	0	116	15	0	0	22	14	1	6	0	0	0	63	0	50	1	0	487
	Upgrade	2	2	0	7	0	0	7	0	0	0	3	1	0	1	0	0	0	6	0	2	0	0	31
Active	New Generation	0	2	0	0	1	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	Upgrade	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Total Projects	New Generation	25	142	0	66	11	0	152	15	0	0	27	15	1	7	0	0	0	87	0	58	1	0	607
	Upgrade	2	6	0	10	0	0	19	0	0	0	3	2	0	1	0	0	0	12	0	2	0	0	57

Table 12-44 shows the status of all wind projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 5,549.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 2,854.6 MW (46.6 percent) are located in the COMED Zone.

Table 12-44 Status of all wind generation serial queue projects by zone (MW): September 30, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	7.5	3,276.2	0.0	1,232.9	0.0	0.0	4,386.7	0.0	0.0	0.0	511.5	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0	0.0	226.5	0.0	0.0	10,688.3
	Upgrade	0.0	268.4	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.9	0.0	0.0	0.0	0.0	592.5
Under Construction	New Generation	0.0	340.3	0.0	80.0	0.0	0.0	1,200.0	0.0	0.0	0.0	78.2	0.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	0.0	0.0	0.0	1,808.4
	Upgrade	0.0	12.6	0.0	0.0	0.0	0.0	105.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	118.5
Suspended	New Generation	432.0	100.0	0.0	80.0	0.0	0.0	278.7	0.0	0.0	0.0	0.0	247.8	0.0	816.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,954.5
	Upgrade	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	107.3
Withdrawn	New Generation	7,653.2	24,731.4	0.0	3,552.2	1,814.0	0.0	27,483.5	2,128.0	0.0	0.0	5,788.5	3,680.8	150.3	4,447.2	0.0	0.0	0.0	5,257.0	0.0	3,835.2	20.0	0.0	90,541.2
	Upgrade	5.0	370.0	0.0	119.4	0.0	0.0	754.0	0.0	0.0	0.0	114.0	30.0	0.0	510.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	2,151.8
Active	New Generation	0.0	263.3	0.0	0.0	297.7	0.0	850.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,411.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0
Total Projects	New Generation	8,092.7	28,711.2	0.0	4,945.1	2,111.7	0.0	34,198.9	2,128.0	0.0	0.0	6,378.2	3,928.6	150.3	5,263.2	0.0	0.0	0.0	6,413.9	0.0	4,061.7	20.0	0.0	106,403.3
	Upgrade	5.0	751.0	0.0	124.4	0.0	0.0	1,223.1	0.0	0.0	0.0	114.0	37.3	0.0	510.0	0.0	0.0	0.0	349.3	0.0	6.0	0.0	0.0	3,120.1

Of the 27 wind units in the serial queue as of September 30, 2025, in the status of active, under construction or suspended, two units, representing 160.0 MW had a projected in service date prior to January 1, 2025 and 25 units, representing 5,389.7 MW had a projected in service date between January 1, 2025, and December 31, 2029.

A total of 48 offshore wind projects entered PJM generation serial queues from January 1, 1997, through July 10, 2023. Offshore wind projects are included in the wind generation statistics. Of the 27 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue (Table 12-43), four projects (14.8 percent) are offshore wind. Of the 5,549.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue (Table 12-44), 1,503.1 MW (27.1 percent) are offshore wind projects. Table 12-43 shows that 519 wind projects have been withdrawn from the serial queue. Of those 519 wind projects, 43 projects (8.3 percent) were offshore wind. Table 12-44 shows that those 519 wind projects that have been withdrawn from the serial queue totaled 92,692.2 MW. Of the 92,692.2 MW of withdrawn wind projects, 16,787.2 MW (18.1 percent) were offshore wind projects.

Solar Project Analysis

Table 12-45 shows the status of all solar generation projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 338 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 100 projects (29.6 percent) are located in the AEP Zone.

Table 12-45 Status of all solar generation serial queue projects by zone (number of projects): September 30, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	11	25	0	24	4	3	2	7	3	3	78	19	3	56	5	0	1	9	3	6	46	0	308
	Upgrade	2	9	0	6	2	0	1	4	3	1	22	12	2	12	0	0	0	1	0	3	4	0	84
Under Construction	New Generation	2	18	0	4	7	0	0	0	0	0	15	5	1	2	0	0	0	4	0	1	1	0	60
	Upgrade	0	1	0	0	1	0	0	0	0	0	10	2	0	1	0	0	0	0	0	0	0	0	15
Suspended	New Generation	1	20	1	6	3	0	1	0	1	0	14	3	0	2	2	0	0	14	2	7	0	0	77
	Upgrade	0	5	0	0	0	0	1	0	0	0	2	2	0	0	1	0	0	2	0	0	0	0	13
Withdrawn	New Generation	192	160	0	133	39	14	55	31	16	1	288	147	20	198	42	2	12	91	25	71	92	0	1,629
	Upgrade	4	13	0	10	4	0	7	2	0	0	32	2	1	9	2	0	0	9	3	5	3	0	106
Active	New Generation	0	46	0	8	8	0	7	7	1	0	20	3	4	3	1	0	0	14	0	9	0	0	131
	Upgrade	0	10	0	1	0	0	3	2	0	0	9	5	1	1	0	0	0	2	0	8	0	0	42
Total Projects	New Generation	206	269	1	175	61	17	65	45	21	4	415	177	28	261	50	2	13	132	30	94	139	0	2,205
	Upgrade	6	38	0	17	7	0	12	8	3	1	75	23	4	23	3	0	0	14	3	16	7	0	260

Table 12-46 shows the status of all solar projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 26,729.0 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 12,287.1 MW (46.0 percent) are located in the AEP Zone.

Table 12-46 Status of all solar generation serial queue projects by zone (MW): September 30, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	67.6	2,506.9	0.0	732.1	548.0	31.1	59.0	699.2	214.9	45.9	4,431.7	360.5	165.0	435.7	160.0	0.0	3.3	326.4	35.6	140.0	241.9	0.0	11,204.7
	Upgrade	0.0	557.0	0.0	60.0	60.0	0.0	50.0	144.8	85.0	8.3	312.8	39.8	40.0	13.1	0.0	0.0	0.0	0.0	0.0	10.0	3.8	0.0	1,384.6
Under Construction	New Generation	11.6	3,064.6	0.0	226.8	344.7	0.0	0.0	0.0	0.0	0.0	2,204.0	363.7	70.0	30.8	0.0	0.0	0.0	242.0	0.0	80.0	6.0	0.0	6,644.2
	Upgrade	0.0	60.0	0.0	0.0	56.0	0.0	0.0	0.0	0.0	0.0	339.9	40.0	0.0	8.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.7
Suspended	New Generation	149.3	2,185.1	40.0	279.1	212.9	0.0	210.0	0.0	100.0	0.0	1,429.9	191.0	0.0	17.0	125.0	0.0	0.0	372.4	40.0	136.8	0.0	0.0	5,488.5
	Upgrade	0.0	129.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	53.0	37.0	0.0	0.0	20.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	319.0
Withdrawn	New Generation	2,300.4	12,428.9	0.0	3,775.6	2,259.2	112.3	4,217.1	2,215.5	689.4	20.0	18,844.0	2,515.4	1,266.9	1,631.3	1,249.7	198.0	124.2	3,024.3	283.9	1,855.1	590.2	0.0	59,601.3
	Upgrade	172.5	473.0	0.0	140.7	279.7	0.0	185.0	62.0	0.0	0.0	1,287.6	15.0	70.0	23.8	40.0	0.0	0.0	90.0	3.6	141.0	1.3	0.0	2,985.2
Active	New Generation	0.0	5,790.9	0.0	553.3	804.0	0.0	670.9	747.8	49.0	0.0	1,676.8	69.6	271.0	51.6	79.6	0.0	0.0	580.3	0.0	275.5	0.0	0.0	11,620.4
	Upgrade	0.0	1,057.5	0.0	78.4	0.0	0.0	190.0	58.5	0.0	0.0	418.0	94.5	40.0	11.0	0.0	0.0	0.0	48.5	0.0	155.9	0.0	0.0	2,152.3
Total Projects	New Generation	2,528.9	25,976.4	40.0	5,566.9	4,168.8	143.4	5,157.0	3,662.5	1,053.3	65.9	28,586.4	3,500.2	1,772.9	2,166.4	1,614.3	198.0	127.5	4,545.4	359.5	2,487.4	838.1	0.0	94,559.0
	Upgrade	172.5	2,276.5	0.0	279.1	395.7	0.0	475.0	265.3	85.0	8.3	2,411.3	226.3	150.0	56.7	60.0	0.0	0.0	168.5	3.6	306.9	5.1	0.0	7,345.8

Of the 338 solar units in the serial queue as of September 30, 2025, in the status of active, under construction or suspended, 21 units, representing 1,641.3 MW had a projected in service date prior to January 1, 2025 and 317 units, representing 25,087.7 MW had a projected in service date between January 1, 2025, and December 31, 2031.

Battery Project Analysis

Table 12-47 shows the status of all battery generation projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 47 battery projects currently active, suspended or under construction in the PJM generation serial queue, 12 projects (25.5 percent) are located in the AEP Zone.

Table 12-47 Status of all battery generation serial queue projects by zone (number of projects): September 30, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	3	0	3	0	2	7	1	4	0	1	0	0	7	0	0	1	0	0	1	2	0	32
	Upgrade	0	1	0	0	0	0	0	1	1	0	0	0	0	3	0	0	0	2	0	0	0	0	8
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	3	0	0	1	0	0	0	0	0	0	0	0	4
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	2	1	0	7
	Upgrade	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Withdrawn	New Generation	12	29	0	5	6	26	21	1	3	2	28	25	2	40	6	0	4	6	2	10	8	0	236
	Upgrade	7	13	0	11	1	0	6	2	1	0	18	3	1	7	4	0	3	11	0	4	0	0	92
Active	New Generation	2	7	0	0	0	1	1	1	0	0	4	1	0	3	0	0	0	0	0	0	4	0	24
	Upgrade	0	1	0	1	0	0	3	1	0	0	1	0	0	0	1	0	0	0	0	0	0	0	8
Total Projects	New Generation	14	42	0	8	6	29	29	3	7	2	36	26	2	51	6	0	5	7	2	13	15	0	303
	Upgrade	7	16	0	12	1	0	10	4	3	0	20	3	1	10	5	0	3	13	0	4	0	0	112

Table 12-48 shows the status of all battery projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 3,426.1 MW of battery generation currently active, suspended or under construction in the PJM generation serial queue, 819.2 MW (23.9 percent) are located in the AEP Zone.

Table 12-48 Status of all battery generation serial queue projects by zone (MW): September 30, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	10.0	0.0	39.9	0.0	3.5	86.0	12.0	16.0	0.0	20.0	0.0	0.0	112.8	0.0	0.0	1.0	0.0	0.0	20.0	3.0	0.0	324.2
	Upgrade	0.0	4.0	0.0	0.0	0.0	0.0	0.0	8.0	4.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	28.4	0.0	0.0	0.0	0.0	52.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	335.7	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	355.7
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0
Suspended	New Generation	0.0	142.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	160.0	0.0	170.0	10.0	0.0	482.0
	Upgrade	0.0	40.0	0.0	0.0	0.0	0.0	10.0	0.0	52.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.2
Withdrawn	New Generation	303.0	1,047.4	0.0	237.0	106.1	280.6	387.0	19.9	75.5	75.0	1,180.4	600.5	46.3	976.1	395.9	0.0	4.3	470.8	21.0	424.8	411.5	0.0	7,063.0
	Upgrade	20.0	769.2	0.0	219.0	20.3	0.0	125.3	95.0	20.0	0.0	441.0	54.0	28.0	55.1	174.0	0.0	60.0	76.0	0.0	40.0	0.0	0.0	2,196.9
Active	New Generation	50.0	585.0	0.0	0.0	0.0	300.0	20.0	85.0	0.0	0.0	250.0	9.0	0.0	290.0	0.0	0.0	0.0	0.0	0.0	0.0	525.0	0.0	2,114.0
	Upgrade	0.0	52.2	0.0	20.0	0.0	0.0	150.0	40.0	0.0	0.0	40.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	322.2
Total Projects	New Generation	353.0	1,784.4	0.0	276.9	106.1	584.1	493.0	116.9	91.5	75.0	1,786.1	609.5	46.3	1,398.9	395.9	0.0	5.3	630.8	21.0	614.8	949.5	0.0	10,338.9
	Upgrade	20.0	865.4	0.0	239.0	20.3	0.0	285.3	143.0	76.2	0.0	531.0	54.0	28.0	63.1	194.0	0.0	60.0	104.4	0.0	40.0	0.0	0.0	2,723.7

Of the 47 battery units in the serial queue as of September 30, 2025, in the status of active, under construction or suspended, two units, representing 40.0 MW had a projected in service date prior to January 1, 2025 and 45 units, representing 3,386.1 MW had a projected in service date between January 1, 2025, and December 31, 2030.

Renewable Hybrid Project Analysis

Table 12-49 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone.[73] Of the 29 renewable hybrid projects currently active, suspended or under construction in the PJM generation serial queue, seven projects (24.1 percent) are located in the AEP Zone and seven projects (24.1 percent) are located in the DOM Zone.

Table 12-49 Status of all renewable hybrid generation serial queue projects by zone (number of projects): September 30, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	1	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	5	0	8
	Upgrade	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	5	15	0	13	7	0	7	0	0	1	35	1	9	3	10	0	0	11	1	20	9	0	147
	Upgrade	0	1	0	2	0	0	0	0	0	0	1	0	0	0	1	0	0	0	0	1	0	0	6
Active	New Generation	2	5	0	2	0	0	1	0	0	1	6	2	0	2	1	0	0	1	0	2	0	0	25
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
Total Projects	New Generation	7	22	0	16	7	0	8	0	0	2	42	4	9	5	11	0	0	12	1	22	14	0	182
	Upgrade	0	3	0	2	0	0	1	0	0	0	2	0	0	0	1	0	0	0	0	1	0	0	10

Table 12-50 shows the status of all renewable hybrid projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 2,522.2 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation serial queue, 1,159.0 MW (46.0 percent) are located in the AEP Zone.

Table 12-50 Status of all renewable hybrid generation serial queue projects by zone (MW): September 30, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	150.0	0.0	186.0	0.0	0.0	0.0	0.0	0.0	0.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	0.0	358.1
	Upgrade	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.9
	Upgrade	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0
Suspended	New Generation	0.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	69.5	4,203.8	0.0	460.5	659.9	0.0	1,004.9	0.0	0.0	20.0	2,759.2	10.0	1,252.0	60.0	78.9	0.0	0.0	455.0	20.0	195.0	49.9	0.0	11,298.5
	Upgrade	0.0	400.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	40.0	0.0	0.0	460.0
Active	New Generation	83.0	909.0	0.0	380.0	0.0	0.0	19.9	0.0	0.0	17.5	534.0	12.7	0.0	120.0	18.2	0.0	0.0	20.0	0.0	60.0	0.0	0.0	2,174.3
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.0
Total Projects	New Generation	152.5	5,412.8	0.0	1,026.5	659.9	0.0	1,024.8	0.0	0.0	37.5	3,310.2	26.5	1,252.0	180.0	97.1	0.0	0.0	475.0	20.0	255.0	54.9	0.0	13,984.7
	Upgrade	0.0	503.2	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	40.0	0.0	0.0	657.2

73 PJM does not currently have a definition of a hybrid resource.

Of the 29 renewable hybrid units in the serial queue as of September 30, 2025, in the status of active, under construction or suspended, two units, representing 6.6 MW had a projected in service date prior to January 1, 2025 and 27 units, representing 2,515.6 MW had a projected in service date between January 1, 2025, and December 31, 2031.

New Service Requests Cycle Process[74]

Interconnection Process Studies and Agreements

The transition to the new queue process began on July 10, 2023. The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[75] Each cycle consists of the: application phase, phase I, decision point I, phase II, decision point II, phase III, decision point III, and the final agreement negotiation phase.

Application Phase

The application phase includes the submission and review of a new service request. A new service request could be a request to interconnect a new generating facility, a request to increase the capability of an existing generating facility, a request to interconnect a merchant transmission facility, a request to increase the capability of an existing merchant transmission facility, a request to interconnect a generating facility to distribution facilities located in PJM that are to be used for transmission of power in interstate commerce, and to make wholesale sales or a long term firm transmission service request outside of the 18 month available transfer capability (ATC) horizon. The deadline for submitting applications for a new cycle corresponds with the completion of phase II of the previous cycle. For an application to be considered complete, and included in a cycle, PJM must receive a completed and executed application and studies agreement (ASA), required technical information, a wire transfer for the entirety of study deposit, a wire transfer or letter of credit for the entirety of Readiness Deposit No. 1 and, for generation requests, evidence of site control.

74 Material in this section is based on information found in PJM Manual 14H. See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 02 (July 23, 2025).

75 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

Phase I

Phase I of a cycle begins after the application phase of a cycle is completed and a group of valid new service requests is established. During phase I of a cycle, PJM performs a phase I system impact study (SIS). The phase I SIS is conducted on an aggregate basis within a cycle, and results are provided in a single cycle format. The phase I SIS results are posted on PJM's website. The phase I SIS evaluates each new service request on a summer peak, winter peak and light load RTEP base case. PJM only performs a load flow analysis during the phase I system impact study. In phase I of the cycle, PJM also conducts an affected system screen and provides each affected system operator with a list of new service requests within the cycle including potential impacts to their system. During phase I, PJM creates both the short circuit and stability base cases that will be used in the phase II SIS.

Decision Point I

New service requests that are studied in phase I will enter decision point I. After reviewing the results of the phase I SIS, the project developer must decide whether or not to move forward to phase II of the process. Decision point I starts on the first business day following the end of phase I and closes 30 calendar days later. Before the close of decision point I, the project developer can choose to either remain in the cycle by meeting the decision point I requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point I, the new service request will be terminated and withdrawn.

Phase II

After the decision point I phase of a cycle is completed and a group of valid new service requests is established, phase II of a cycle will begin. During phase II of a cycle, PJM performs the phase II SIS. PJM retools the load flow results from the phase I SIS (summer peak, winter peak and light load) based on decisions made during decision point I. PJM also conducts any required voltage analyses, performs short circuit and stability analyses and coordinates with affected systems to confirm which projects in the cycle will require affected system studies. If the affected system operator indicates that an affected system study is required, PJM notifies the project developer of the need for an affected system study and the requirement to execute an affected system study agreement with the impacted affected system operator. If applicable and available, PJM includes the results of the affected system operator's affected system study in the phase II SIS results.

The phase II SIS includes a facilities study by the affected transmission owner that identifies any required network upgrades. The facilities studies will include good faith estimates of the costs to be charged to each affected new service customer for the network upgrades that are necessary to accommodate each new service request evaluated in the study, the time required to complete detailed design and construction of the facilities and upgrades and a description of any site-specific environmental issues or requirements that could reasonably be anticipated to affect the cost or time required to complete construction of such facilities and upgrades.

Decision Point II

New service requests that are studied in phase II will enter decision point II. After reviewing the results of the phase II SIS, the project developer must decide whether or not to move forward to phase III of the process. Decision point II starts on the first business day following the end of phase II and closes 30 calendar days later. Before the close of decision point II, the project developer can choose to either remain in the cycle by meeting the decision point II requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point II, the new service request will be terminated and withdrawn.

Phase III

After the decision point II phase of a cycle is completed and a group of valid new service requests is established, phase III of a cycle will begin. During phase III of a cycle, PJM performs the phase III SIS. PJM retools the load flow, short circuit and stability results from the phase II SIS based on decisions made during decision point II. PJM also coordinates with affected systems to conduct any studies required to determine the final impact of a new service request on any affected system. If applicable and available, PJM includes the results of the affected system operator's final affected system study in the phase III SIS results.

Decision Point III

New service requests that are studied in phase III will enter decision point III. After reviewing the results of the phase III SIS, the project developer must decide whether or not to move forward to the final agreement negotiation phase. Decision point III starts on the first business day following the end of phase III and runs concurrently with the final agreement negotiation phase. The project developer can choose to either remain in the cycle by meeting the decision point III requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point III, the new service request will be terminated and withdrawn.

Final Agreement Negotiation Phase

The final agreement negotiation phase starts on the first business day immediately following the end of phase III, and runs concurrently with decision point III. The purpose of the final agreement negotiation phase is to negotiate, execute and enter into the applicable final interconnection related service agreement, conduct any remaining analyses or updated analyses based on new service requests withdrawn during decision point III and adjust the security obligation based on new service requests withdrawn during decision point III and/or during the final agreement negotiation phase. PJM uses reasonable efforts to complete the final agreement negotiation phase within 60 days. Table 12-51 is an overview of the agreements used in the new service requests cycle process.

Table 12-51 Final agreements: new service requests cycle process

Agreement	Purpose
Generation Interconnection Agreement (GIA)	The GIA defines the obligations of the project developer regarding cost responsibility for any required system upgrades. The GIA also confers the rights associated with the interconnection of a generating facility as a capacity resource and any operational restrictions or other limitations on which those rights depend. For transmission project developers, the GIA confers transmission injection and withdrawal rights and applicable incremental delivery rights and incremental auction revenue rights.The GIA further identifies any changes in construction responsibility from the standard option for transmission owner interconnection facilities due to the project developer exercising the negotiated contract option or option to build.
Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.The CSA is included as a schedule within a GIA; however, a stand-alone CSA may be implemented in circumstances in which network upgrades to the system of a transmission owner are required to accommodate the interconnection request of a project developer, whose facilities do not directly interconnect to the transmission owner's system. Examples include project developers who are affected system customers (external to the PJM region), that require network upgrades to be constructed by PJM transmission owners, or project developers requiring upgrades to be constructed by PJM transmission owners, other than their interconnecting transmission owner
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Network Upgrade Cost Responsibility Agreement (NUCRA)	The NUCRA refers to the agreement entered into by two or more project developers and PJM, relating to construction of common use upgrades (network upgrades needed for the interconnection of generating or merchant transmission facilities for more than one project developer that share cost responsibility) and coordination of the construction and interconnection of associated generating facilities. A separate NUCRA will be executed for each set of common use upgrades on the system of a specific transmission owner that is associated with the interconnection of a generating facility or merchant transmission facility. The NUCRA includes the identified common use upgrades scope and schedule of work, the cost responsibility for the project developers that share cost responsibility, as well as the terms and conditions for the agreement.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

Transition Cycle 1 (TC1)

On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[76] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[77] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The transition to the new queue process began on July 10, 2023.

On May 20, 2024, PJM completed the phase I system impact study for transition cycle 1 (TC1). Developers had 30 days (until June 20, 2024) to decide whether to proceed with their new service requests into the next study phase of TC1 or to withdraw their projects. Continuing with phase II required developers to meet the decision point I requirements (including additional readiness deposits and proof of site control).[78]

On December 20, 2024, PJM completed the phase II system impact study for TC1. Developers had 30 days (until January 19, 2025) to decide whether to proceed with their new service requests into the next study phase of TC1 or to withdraw their projects. Continuing with phase III requires developers to meet the decision point II requirements, (including additional readiness deposits and proof of site control).[79]

On April 21, 2025, phase III of TC1 began. During phase III, PJM performed the phase III SIS. PJM retooled the load flow, short circuit and stability results from the phase II SIS based on decisions made during decision point II. PJM also coordinated with affected systems to conduct any studies required to determine the final impact of a new service request on any affected system. Phase III of TC1 completed on September 19, 2025. The TC1 decision point III runs for 30 days, and is scheduled to be completed on October 21, 2025. Additionally, the TC1 final agreement phase also began at the completion of phase III, and is scheduled to be completed on November 20, 2025.

76 181 FERC ¶ 61,162 (2022).
77 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.
78 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 02 (July 23, 2025) for a complete list of all readiness requirements.
79 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 02 (July 23, 2025) for a complete list of all readiness requirements.

Planned Generation Additions

TC1 is comprised of 312 proposed generation projects. Those projects make up 40,650.2 MW. On September 30, 2025, all projects in TC1 were either in the status of active or were withdrawn from the cycle. Table 12-52 shows each status by unit type. Of the 40,650.2 MW in TC1, 17,873.8 MW (44.0 percent) were active and 22,776.3 MW (56.0 percent) were withdrawn. Of the 17,873.8 MW in the status of active, 9,762.3 MW (54.6 percent) were solar projects, 4,377.3 MW (24.5 percent) were wind projects, and 2,254.2 MW (12.6 percent) were battery projects.

Table 12-52 Transition cycle 1 project status (MW) by unit type: September 30, 2025

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	2,254.2	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,762.3	911.0	0.0	0.0	0.0	0.0	0.0	4,377.3	0.0	17,873.8
Withdrawn	4,028.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,167.7	3,197.2	199.0	0.0	0.0	0.0	0.0	4,184.3	0.0	22,776.3
Total	6,282.4	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20,930.0	4,108.2	199.0	0.0	0.0	0.0	0.0	8,561.6	0.0	40,650.2

Table 12-53 shows the projects in TC1 with a status of active or under construction, by unit type, and control zone. As of September 30, 2025, 17,873.8 MW were in TC1 for construction through 2031. Table 12-53 also shows the planned retirements for each zone.

Table 12-53 Transition cycle 1 totals for projects (active and under construction) by LDA, control zone and unit type (MW): September 30, 2025

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	175.1
	DPL	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.0	16.4
	JCPLC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.0
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	760.0
	PSEG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	95.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	195.0	1,016.5
SWMAAC	BGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,975.0
	PEPCO	500.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0
	SWMAAC Total	500.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	1,975.0
WMAAC	MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	202.8	245.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	447.8	0.0
	PPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WMAAC Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	202.8	245.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	447.8	0.0
Non-MAAC	AEP	957.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,555.0	500.0	0.0	0.0	0.0	0.0	0.0	755.0	0.0	3,767.2	2,620.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	APS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	ATSI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	16.5
	COMED	380.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,953.1	0.0	0.0	0.0	0.0	0.0	0.0	1,133.3	0.0	5,466.4	2,607.9
	DAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.6	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	246.6	0.0
	DUKE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DLCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DOM	300.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,415.2	20.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	5,793.2	0.0
	EKPC	22.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,317.7	106.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,445.7	116.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	1,659.2	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,459.6	666.0	0.0	0.0	0.0	0.0	0.0	4,377.3	0.0	16,731.1	5,360.4
Total		2,254.2	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,762.3	911.0	0.0	0.0	0.0	0.0	0.0	4,377.3	0.0	17,873.8	8,351.9

Table 12-54 shows that on September 30, 2025 there were 17,873.8 MW, on an energy basis, of which 8,854.3 MW are on a capacity basis that requested CIRs, in TC1 in the status of active or under construction. Table 12-54 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 8,854.3 MW, on a capacity basis that requested CIRs in TC1 in the status of active or under construction, 2,152.8 MW (24.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 5,082.0 MW, on a capacity basis that requested CIRs, of solar projects requested in TC1 in the status of active or under construction, 406.6 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 1,565.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC1 in the status of active or under construction, 907.9 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 6,720.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC1 in the status of active or under construction, 897.9 MW (13.4 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Table 12-54 Transition cycle 1 totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): September 30, 2025

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	2,254.2	1,565.3	907.9
CC	0.0	0.0	0.0
CT - Natural Gas	569.0	569.0	347.1
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	9,762.3	5,082.0	406.6
Solar + Storage	911.0	546.3	43.7
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	4,377.3	1,091.7	447.6
Wind + Storage	0.0	0.0	0.0
Total	17,873.8	8,854.3	2,152.8

Withdrawn Projects

Table 12-55 shows the status of all TC1 projects as they have progressed through the cycle process. Of the 312 projects included in TC1, 121 projects (38.8 percent of all projects and 38.9 percent of the total MW) were withdrawn during phase I or decision point I and 61 projects (19.6 percent of all projects and 17.1 percent of the total MW) were withdrawn during phase II or decision point II. On September 30, 2025, 130 projects (41.6 percent of all projects and 44.0 percent of the total MW) remain active in TC1.

Table 12-55 Transition cycle 1 status: September 30, 2025

	Number of Projects	Percent of Projects	MW Energy	Percent of MW Energy
Transition cycle 1 approved projects	312	100.0%	40,650.2	100.0%
Withdrawn prior to start of phase I	0	0.0%	0.0	0.0%
Withdrawn during phase I or decision point I	121	38.8%	15,821.8	38.9%
Withdrawn during phase II or decision point II	61	19.6%	6,954.5	17.1%
Active as of September 30, 2025	128	41.0%	17,353.8	42.7%
In final agreement stage as of September 30, 2025	2	0.6%	520.0	1.3%
Under construction	0	0.0%	0.0	0.0%
In Service	0	0.0%	0.0	0.0%

Table 12-56 shows 40,650.2MW have entered TC1. Table 12-56 presents totals by fuel type and projected in service date as of September 30, 2025. Of the 40,650.2 MW to enter TC1, 569.0 MW (1.4 percent) were thermal units.

Table 12-56 Transition cycle 1 total (MW Energy) by unit type and projected in service year: September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	729.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,299.5	1,826.8	0.0	0.0	0.0	0.0	0.0	2,112.2	0.0	6,967.9
2020	3,298.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,988.2	1,370.4	199.0	0.0	0.0	0.0	0.0	2,072.2	0.0	15,928.4
2021	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	927.6	20.0	0.0	0.0	0.0	0.0	0.0	413.4	0.0	1,461.0
2022	507.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,574.5	450.0	0.0	0.0	0.0	0.0	0.0	595.9	0.0	4,127.5
2023	730.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,012.3	441.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0	6,252.3
2024	397.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,128.0	0.0	0.0	0.0	0.0	0.0	0.0	1,199.0	0.0	3,724.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	833.0	0.0	833.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	836.0	0.0	836.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	500.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	6,282.4	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20,930.0	4,108.2	199.0	0.0	0.0	0.0	0.0	8,561.6	0.0	40,650.2

Table 12-57 shows there were 17,873.8 MW in TC1 in the status of active or under construction as of September 30, 2025. Table 12-57 presents totals by fuel type and projected in service date. Of the 17,873.8 MW, 569.0 MW (3.2 percent) are thermal units.

Table 12-57 Transition cycle 1 total (MW Energy) by unit type and projected in service year (active and under construction): September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.0
2021	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	927.6	20.0	0.0	0.0	0.0	0.0	0.0	413.4	0.0	1,461.0
2022	507.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,574.5	450.0	0.0	0.0	0.0	0.0	0.0	595.9	0.0	4,127.5
2023	730.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,012.3	441.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0	6,252.3
2024	397.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,128.0	0.0	0.0	0.0	0.0	0.0	0.0	1,199.0	0.0	3,724.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	833.0	0.0	833.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	836.0	0.0	836.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	500.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	2,254.2	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,762.3	911.0	0.0	0.0	0.0	0.0	0.0	4,377.3	0.0	17,873.8

Table 12-58 shows there were 22,776.3 MW withdrawn from TC1. Table 12-58 presents totals by fuel type and projected in service date. Of the 22,776.3 MW withdrawn from TC1, none were identified as thermal units.

Table 12-58 Transition cycle 1 total (MW Energy) by unit type and projected in service year (withdrawn): September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	729.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,299.5	1,826.8	0.0	0.0	0.0	0.0	0.0	2,112.2	0.0	6,967.9
2020	3,298.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,868.2	1,370.4	199.0	0.0	0.0	0.0	0.0	2,072.2	0.0	15,808.4
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,028.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,167.7	3,197.2	199.0	0.0	0.0	0.0	0.0	4,184.3	0.0	22,776.3

Analysis by Fuel Group

Table 12-59 shows the number of projects that entered TC1 by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). The 312 projects submitted to TC1 were made up of 233 renewable projects (74.7 percent), 77 storage projects (24.7 percent) and two thermal projects (0.6 percent).

Table 12-59 Transition cycle 1 number of projects by fuel group: September 30, 2025

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
2018	0	0.0%	4	80.0%	0	0.0%	1	20.0%	0	0.00%	5
2019	0	0.0%	57	78.1%	15	20.5%	1	1.4%	0	0.00%	73
2020	0	0.0%	172	73.5%	62	26.5%	0	0.0%	0	0.00%	234
Total	0	0.0%	233	74.7%	77	24.7%	2	0.6%	0	0.00%	312

As of September 30, 2025, there were 130 projects in TC1 in the status of active or under construction. Those 130 projects consisted of 104 renewable projects (80.0 percent of all projects and 84.2 percent of the nameplate MW), 25 storage projects (19.2 percent of all projects and 12.6 percent of the nameplate MW) and one thermal project (0.8 percent of all projects and 3.2 percent of the nameplate MW) (Table 12-60).

Table 12-60 Transition cycle 1 details by fuel group: September 30, 2025

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	0	0.0%	0.0	0.0%
Renewable	104	80.0%	15,050.6	84.2%
Storage	25	19.2%	2,254.2	12.6%
Thermal	1	0.8%	569.0	3.2%
Other	0	0.0%	0.0	0.0%
Total	130	100.0%	17,873.8	100.0%

Analysis by Unit Type and Project Classification

Table 12-61 shows the status of all new generation projects in TC1 by unit type and project classification as of September 30, 2025. Project classification is defined as either new generation or an uprate in which existing resources are modified to increase the economic maximum generation capability. There were 312 projects, representing 40,650.2 MW, entered into TC1. Of those, 312 projects, 182 projects, representing 22,776.3 MW (56.0 percent of the MW) withdrew prior to completion.

A total of 218 projects have been classified as new generation and 94 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 235 projects (75.3 percent) of all 312 generation projects to enter TC1.

Table 12-61 Transition Cycle 1 status of all generation projects: September 30, 2025

Project Status	Project Classification	Number of Projects																					
		Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	21	0	0	0	0	0	0	0	0	0	0	0	73	25	1	0	0	0	0	11	0	131
	Upgrade	31	0	1	0	0	0	0	0	0	0	0	0	13	4	0	0	0	0	0	2	0	51
Active	New Generation	11	0	1	0	0	0	0	0	0	0	0	0	58	7	0	0	0	0	0	10	0	87
	Upgrade	14	0	0	0	0	0	0	0	0	0	0	0	25	0	0	0	0	0	0	4	0	43
Total Projects	New Generation	32	0	1	0	0	0	0	0	0	0	0	0	131	32	1	0	0	0	0	21	0	218
	Upgrade	45	0	1	0	0	0	0	0	0	0	0	0	38	4	0	0	0	0	0	6	0	94

Table 12-62 shows the totals in Table 12-61 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 31.1 percent of all battery projects in TC1 classified as upgrades were active and 68.9 percent of battery projects classified as upgrades were withdrawn from TC1 as of September 30, 2025.

Table 12-62 Transition Cycle 1 status of all generation projects as a percent of total projects by classification: September 30, 2025

Project Status	Project Classification	Percent of Projects																					
		Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	New Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	65.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	55.7%	78.1%	100.0%	0.0%	0.0%	0.0%	0.0%	52.4%	0.0%	60.1%
	Upgrade	68.9%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	34.2%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	33.3%	0.0%	54.3%
Active	New Generation	34.4%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	44.3%	21.9%	0.0%	0.0%	0.0%	0.0%	0.0%	47.6%	0.0%	39.9%
	Upgrade	31.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	65.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	66.7%	0.0%	45.7%

Table 12-63 shows the total MW of projects in TC1 by unit type and project classification. For example, the 21 new generation battery projects that have been withdrawn from TC1 as of September 30, 2025, (as shown in Table 12-61) constitute 2,929.7 MW. The 73 new generation solar projects that have been withdrawn in the same time period constitute 9,722.7 MW.

Table 12-63 Transition cycle 1 status of all generation (MW) projects: September 30, 2025

		Project MW																					
Project Status	Project Classification	Battery	CC	CT – Natural Gas	CT – Oil	CT – Other	Fuel Cell	Hydro – Pumped Storage	Hydro – Run of River	Nuclear	RICE – Natural Gas	RICE – Oil	RICE – Other	Solar	Solar + Storage	Solar + Wind	Steam – Coal	Steam – Natural Gas	Steam – Oil	Steam – Other	Wind	Wind + Storage	Total
In Service	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	2,929.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,722.7	2,934.8	199.0	0.0	0.0	0.0	0.0	3,726.2	0.0	19,512.3
	Upgrade	1,098.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,445.0	262.4	0.0	0.0	0.0	0.0	0.0	458.2	0.0	3,264.1
Active	New Generation	1,695.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,557.2	911.0	0.0	0.0	0.0	0.0	0.0	3,938.9	0.0	14,671.1
	Upgrade	559.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,205.1	0.0	0.0	0.0	0.0	0.0	0.0	438.4	0.0	3,202.7
Total Projects	New Generation	4,624.7	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17,279.9	3,845.8	199.0	0.0	0.0	0.0	0.0	7,665.1	0.0	34,183.4
	Upgrade	1,657.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,650.1	262.4	0.0	0.0	0.0	0.0	0.0	896.6	0.0	6,466.8

Table 12-64 shows the MW totals in Table 12-63 share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 33.7 percent of all battery project MW in TC1 classified as upgrades were active and 66.3 percent of battery project MW classified as upgrades were withdrawn from TC1 as of September 30, 2025.

Table 12-64 Transition cycle 1 status of all generation projects as percent of total MW in project classification: September 30, 2025

		Percent of Total Projects by Classification																					
Project Status	Project Classification	Battery	CC	CT – Natural Gas	CT – Oil	CT – Other	Fuel Cell	Hydro – Pumped Storage	Hydro – Run of River	Nuclear	RICE – Natural Gas	RICE – Oil	RICE – Other	Solar	Solar + Storage	Solar + Wind	Steam – Coal	Steam – Natural Gas	Steam – Oil	Steam – Other	Wind	Wind + Storage	Total
In Service	New Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	New Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	63.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	56.3%	76.3%	100.0%	0.0%	0.0%	0.0%	0.0%	48.6%	0.0%	57.1%
	Upgrade	66.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	39.6%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	51.1%	0.0%	50.5%
Active	New Generation	36.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	43.7%	23.7%	0.0%	0.0%	0.0%	0.0%	0.0%	51.4%	0.0%	42.9%
	Upgrade	33.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	60.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	48.9%	0.0%	49.5%

Transition Cycle 2 (TC2) and Reliability Resource Initiative (RRI)

On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[80] The MMU supports the stated goals of the December 13th Filing, and supported approval of the December 13th Filing, but also identified significant flaws that compromise the ability of the proposal to achieve its stated goals.[81] PJM's RRI scoring criteria placed undue emphasis on ELCC values rather than on dispatchability. PJM stated that the goal is to be fuel and technology neutral. That is not the appropriate objective when there are defined differences in reliability and dispatchability across resource types, by fuel and technology. The goal of the December 13th Filing should have been to select the most reliable fuel and technology combinations. PJM also focused on an arbitrary number of projects (50) that could qualify as RRI projects rather than on a target level of MW needed for reliability. PJM should have identified the number of MW, with the required reliability characteristics, that it believes are needed to address PJM's identified reliability shortfall and use the RRI process to obtain those MW. PJM's RRI scoring criteria should have been a series of thresholds that must be met in sequence rather than a single formula that considers all elements simultaneously and assumes that the criteria are comparable through relative weights. The first threshold should have been that the resource is in the right location to address the identified locational reliability issue. The second threshold should have been that the operational characteristics of the resource fully address the identified reliability issue including technology and fuel source(s). The third threshold should have been commercial viability within a defined time period with detailed tracking and strong financial incentives. No RRI resource should have been approved unless it met all three thresholds.

In addition to the one time RRI process, the MMU recommends that PJM establish an ongoing expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[82] While it is important to respect the existing, improved PJM queue process, it is also essential to provide strong and clear incentives for projects to actually resolve reliability issues and to actually guarantee timely in service dates in order to help ensure that the queue is not a mirage as it has been in significant part for its recent history. Recognizing that improved queue rules are being implemented, the history of queue projects becoming actual in service capacity resources suggests strongly that such incentives have not been provided by the queue process.

On February 11, 2025, the Commission approved the RRI tariff modifications.[83] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period.

PJM included a range of important enforceable provisions that help ensure that the selected RRI resources will actually go online as promised. These provisions include a must offer obligation which is essential to the efficacy of the entire filing as capacity resources that do not offer do not help solve the identified problem. The MMU supports these provisions.

PJM received 97 applications (28.6 GW) of RRI projects during the RRI application window. Of these projects, 48 involve uprates, in which existing resources are modified to increase the economic maximum generation capability, and 49 propose building new generation. The RRI application window did not limit the number and type of projects (or any restriction on fuel type of projects) that may apply to enter the RRI process. However, PJM restricted the number of RRI projects to be added to TC2 by scoring all the RRI applications using weighted criteria to determine the 50 projects that best

80 See *PJM Interconnection L.L.C.* Docket No. ER25-712 (December 13, 2024).
81 See IMM Comments. *PJM Interconnection L.L.C.* Docket No. ER25-712

82 The MMU has consistently supported a stronger role for PJM in addressing immediate reliability needs. As part of the CIR Transfer Efficiency initiative, the MMU proposed to allow PJM to initiate an expedited fast track process to address PJM identified reliability issues. The proposed expedited process would have allowed PJM to open a limited scope expedited reliability process to select projects that address the reliability issues. See "CIR Transfer Efficiency IMM Package," MMU presentation to the PJM Planning Committee (October 8, 2024), <https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_PC_CIR_Transfer_Efficiency_IMM_Package_20241008_v2.pdf>.
83 190 FERC ¶ 61,084 (February 11, 2025).

satisfy the need for reliable capacity that can be available relatively quickly. The submitted RRI projects were reviewed to determine which projects will be added to TC2.

PJM reviewed the submitted RRI projects using the Commission approved scoring criteria, and approved 51 projects (11,577.4 MW).[84] Table 12-65 shows the status of the 51 approved RRI projects by unit type. On September 30, 2025, all approved RRI projects were either in the status of active or were withdrawn from the cycle. Of the 11,577.4 MW of approved RRI projects, 10,938.4 MW (94.5 percent) were active and 639.0 MW (5.5 percent) were withdrawn. Of the 10,938.4 MW in the status of active, 7,749.6 MW (70.8 percent) were combined cycle projects, and 1,675.0 MW (15.3 percent) were battery projects.

Table 12-65 RRI project status (MW) by unit type: September 30, 2025

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	1,675.0	7,749.6	11.0	0.0	0.0	0.0	0.0	0.0	1,502.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,938.4
Withdrawn	600.0	39.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	639.0
Total	2,275.0	7,788.6	11.0	0.0	0.0	0.0	0.0	0.0	1,502.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,577.4

Table 12-66 shows that on September 30, 2025 there were 10,938.4 MW, on an energy basis, of which 10,439.8 MW are on a capacity basis that requested CIRs, of RRI projects in the status of active or under construction. Table 12-66 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 10,439.8 MW, on a capacity basis that requested CIRs, of RRI projects in the status of active or under construction, 7,726.7 MW (74.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 7,420.9 MW, on a capacity basis that requested CIRs, of RRI combined cycle projects in the status of active or under construction, 5,491.5 MW (74.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 1,675.0 MW, on a capacity basis that requested CIRs, of RRI battery projects in the status of active or under construction, 971.5 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

84 The RRI proposal was to select the top 50 projects using the approved scoring criteria. The implemented scoring criteria resulted in a tie for the 50th project. This resulted in PJM selecting 51 projects as part of the RRI process.

Table 12-66 RRI totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): September 30, 2025

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	1,675.0	1,675.0	971.5
CC	7,749.6	7,420.9	5,491.5
CT - Natural Gas	11.0	38.0	23.2
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	1,502.8	1,305.9	1,240.6
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	0.0	0.0	0.0
Solar + Storage	0.0	0.0	0.0
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	0.0	0.0	0.0
Wind + Storage	0.0	0.0	0.0
Total	10,938.4	10,439.8	7,726.7

The application phase for TC2 opened on June 20, 2024, coincident with the close of phase I of transition cycle 1. The application phase required all active projects in queues AG2 and AH1 to reapply under the new rules. The application phase of TC2 was open for 180 days, and closed on December 17, 2024.

There were 1,347 projects (103,151.7 MW) eligible to resubmit for evaluation in TC2. Of those 1,347 eligible projects, 550 projects (50,023.2 MW) resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects (53,155.5 MW) did not resubmit, and were withdrawn from the queue.

The TC2 application review stage began at the close of the application phase. PJM will review the submissions for required data and deposits and build the models required for the TC2 system impact studies. The TC2 application review stage completed on July 6, 2025. Phase I of TC2 began on July 7, 2025 and is set to be completed on October 31, 2025.

Planned Generation Additions

TC2 is comprised of 647 proposed generation projects. TC2 includes 550 projects submitted during the TC2 window, and 97 projects submitted through the RRI window. Those projects make up 78,329.4 MW. On September 30, 2025, all projects in TC2 were either in the status of active or were withdrawn from the cycle. Table 12-67 shows each status by unit type. Of the 78,329.4 MW in TC2, 45,977.6 MW (58.7 percent) were active and 32,351.8 MW (41.3 percent) were withdrawn. Of the 45,977.6 MW in the status of active, 19,308.1 MW (42.0 percent) are solar projects, 1,235.2 MW (2.7 percent) are wind projects, and 9,404.9 MW (20.5 percent) are battery projects.

Table 12-67 Transition cycle 2 and RRI project status (MW) by unit type: September 30, 2025

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	9,404.9	9,849.6	763.0	0.0	0.0	5.0	0.0	14.0	1,502.8	0.0	0.0	0.0	19,308.1	3,885.0	0.0	0.0	0.0	0.0	10.1	1,235.2	0.0	45,977.6
Withdrawn	10,511.0	10,836.6	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	5,926.8	2,331.3	10.0	0.0	0.0	0.0	3.2	2,727.6	0.0	32,351.8
Total	19,915.9	20,686.2	763.0	0.0	0.0	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	25,234.9	6,216.3	10.0	0.0	0.0	0.0	13.3	3,962.8	0.0	78,329.4

Table 12-68 shows the projects in TC2 with a status of active or under construction, by unit type, and control zone. As of September 30, 2025, 45,977.6 MW were in TC2 for construction through 2031. Table 12-68 also shows the planned retirements for each zone.

Table 12-68 Transition cycle 2 and RRI totals for projects (active and under construction) by LDA, control zone and unit type (MW): September 30, 2025

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	759.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	170.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	929.1	175.1
	DPL	115.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	275.2	41.8	0.0	0.0	0.0	0.0	0.0	516.8	0.0	948.8	16.4
	JCPLC	80.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	197.9	65.0
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	760.0
	PSEG	0.0	293.2	0.0	0.0	0.0	0.0	0.0	0.0	256.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	550.0	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	954.0	293.2	0.0	0.0	0.0	0.0	0.0	0.0	256.8	0.0	0.0	0.0	563.2	41.8	0.0	0.0	0.0	0.0	0.0	516.8	0.0	2,625.8	1,016.5
SWMAAC	BGE	635.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	690.0	1,975.0
	PEPCO	0.0	53.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0	670.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	833.7	0.0
	SWMAAC Total	635.0	53.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	165.0	670.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,523.7	1,975.0
WMAAC	MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0
	PE	210.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,515.8	65.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,790.8	0.0
	PPL	0.0	32.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	183.4	0.0
	WMAAC Total	210.0	32.4	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0	0.0	0.0	1,666.8	65.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,833.2	0.0
Non-MAAC	AEP	2,467.0	1,372.0	752.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,478.3	759.4	0.0	0.0	0.0	0.0	10.1	0.0	0.0	11,838.8	2,620.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	APS	486.9	2,370.3	0.0	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	1,330.5	319.0	0.0	0.0	0.0	0.0	0.0	468.4	0.0	4,989.1	0.0
	ATSI	150.0	1,990.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	527.0	110.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,777.7	16.5
	COMED	1,187.0	0.0	11.0	0.0	0.0	5.0	0.0	0.0	387.0	0.0	0.0	0.0	2,973.6	459.8	0.0	0.0	0.0	0.0	0.0	250.0	0.0	5,273.4	2,607.9
	DAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DUKE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DLCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	0.0
	DOM	3,265.0	2,951.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,290.5	1,275.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,782.6	0.0
	EKPC	50.0	786.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	910.0	184.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,930.3	116.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	398.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	398.5	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	7,605.9	9,470.6	763.0	0.0	0.0	5.0	0.0	14.0	387.0	0.0	0.0	0.0	16,913.1	3,108.0	0.0	0.0	0.0	0.0	10.1	718.4	0.0	38,994.9	5,360.4
Total		9,404.9	9,849.6	763.0	0.0	0.0	5.0	0.0	14.0	1,502.8	0.0	0.0	0.0	19,308.1	3,885.0	0.0	0.0	0.0	0.0	10.1	1,235.2	0.0	45,977.6	8,351.9

Table 12-69 shows that on September 30, 2025 there were 45,977.6 MW, on an energy basis, of which 32,120.8 MW are on a capacity basis that requested CIRs, in TC2 in the status of active or under construction. Table 12-69 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 32,120.8 MW, on a capacity basis that requested CIRs in TC2 in the status of active or under construction, 14,167.2 MW (44.1 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 10,051.8 MW, on a capacity basis that requested CIRs, of solar projects requested in TC2 in the status of active or under construction, 804.1 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 7,400.0 MW, on a capacity basis that requested CIRs, of battery projects requested in TC2 in the status of active or under construction, 4,292.0 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 13,167.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC2 in the status of active or under construction, 1,146.4 MW (8.7 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Table 12-69 Transition cycle 2 and RRI totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): September 30, 2025

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	9,404.9	7,400.0	4,292.0
CC	9,849.6	9,495.9	7,027.0
CT - Natural Gas	763.0	738.0	450.2
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	5.0	5.0	4.6
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	14.0	14.0	5.5
Nuclear	1,502.8	1,305.9	1,240.6
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	19,308.1	10,051.8	804.1
Solar + Storage	3,885.0	2,832.5	226.6
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	10.1	9.1	6.5
Wind	1,235.2	268.7	110.2
Wind + Storage	0.0	0.0	0.0
Total	45,977.6	32,120.8	14,167.2

Withdrawn Projects

Table 12-70 shows the status of all TC2 projects as they have progressed through the cycle process. Of the 647 projects included in TC2, 46 projects (7.1 percent of all projects and 21.7 percent of the total MW) were withdrawn as part of the RRI evaluation, 51 projects (7.9 percent of all projects and 6.6 percent of the total MW) were withdrawn prior to the beginning of phase I, and 100 projects (15.5 percent of all projects and 12.9 percent of the total MW) were withdrawn during phase I or decision point I. On September 30, 2025, 450 projects (69.6 percent of all projects and 58.7 percent of the total MW) remain active in TC2.

Table 12-70 Transition cycle 2 and RRI status: September 30, 2025

	Number of Projects	Percent of Projects	MW Energy	Percent of MW Energy
Transition cycle 2 approved projects	647	100.0%	78,329.4	100.0%
RRI projects not selected	46	7.1%	17,014.8	21.7%
Withdrawn prior to start of phase I	51	7.9%	5,201.1	6.6%
Withdrawn during phase I or decision point I	100	15.5%	10,135.8	12.9%
Withdrawn during phase II or decision point II	0	0.0%	0.0	0.0%
Active as of September 30, 2025	450	69.6%	45,977.6	58.7%
In final agreement stage as of September 30, 2025	0	0.0%	0.0	0.0%
Under construction	0	0.0%	0.0	0.0%
In Service	0	0.0%	0.0	0.0%

Table 12-71 shows 78,329.4 MW have entered TC2. Table 12-71 presents totals by fuel type and projected in service date as of September 30, 2025. Of the 78,329.4 MW to enter TC2, 21,449.2 MW (27.4 percent) were thermal units.

Table 12-71 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year: September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	107.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	399.9	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	539.9
2021	4,377.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	5,417.5	1,715.3	10.0	0.0	0.0	0.0	0.0	2,727.6	0.0	14,252.7
2022	290.0	0.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	459.4	275.0	0.0	0.0	0.0	0.0	0.0	147.0	0.0	1,223.4
2023	1,534.9	0.0	0.0	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	2,215.3	1,198.3	0.0	0.0	0.0	0.0	10.1	0.0	0.0	4,972.5
2024	3,771.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,228.4	840.0	0.0	0.0	0.0	0.0	0.0	318.0	0.0	15,157.4
2025	8,133.0	10,918.6	0.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	5,574.4	2,154.7	0.0	0.0	0.0	0.0	3.2	770.2	0.0	27,559.1
2026	0.0	2,119.0	700.0	0.0	0.0	0.0	0.0	0.0	88.0	0.0	0.0	0.0	870.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,777.0
2027	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	1,245.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,445.8
2028	128.0	20.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	229.0
2029	1,575.0	127.2	0.0	0.0	0.0	0.0	0.0	0.0	169.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,871.2
2030	0.0	2,894.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,894.9
2031	0.0	4,406.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,406.6
Total	19,915.9	20,686.2	763.0	0.0	0.0	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	25,234.9	6,216.3	10.0	0.0	0.0	0.0	13.3	3,962.8	0.0	78,329.4

Table 12-72 shows there were 45,977.6 MW in TC2 in the status of active or under construction as of September 30, 2025. Table 12-72 presents totals by fuel type and projected in service date. Of the 45,977.6 MW, 10,612.6 MW (23.1 percent) are thermal units.

Table 12-72 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year (active and under construction): September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	74.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.6
2022	290.0	0.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	459.4	275.0	0.0	0.0	0.0	0.0	0.0	147.0	0.0	1,223.4
2023	1,534.9	0.0	0.0	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	2,215.3	1,198.3	0.0	0.0	0.0	0.0	10.1	0.0	0.0	4,972.5
2024	3,771.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,228.4	840.0	0.0	0.0	0.0	0.0	0.0	318.0	0.0	15,157.4
2025	2,086.0	82.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	5,390.4	1,571.7	0.0	0.0	0.0	0.0	0.0	770.2	0.0	9,905.3
2026	0.0	2,119.0	700.0	0.0	0.0	0.0	0.0	0.0	88.0	0.0	0.0	0.0	870.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,777.0
2027	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	1,245.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,445.8
2028	128.0	20.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	229.0
2029	1,575.0	127.2	0.0	0.0	0.0	0.0	0.0	0.0	169.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,871.2
2030	0.0	2,894.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,894.9
2031	0.0	4,406.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,406.6
Total	9,404.9	9,849.6	763.0	0.0	0.0	5.0	0.0	14.0	1,502.8	0.0	0.0	0.0	19,308.1	3,885.0	0.0	0.0	0.0	0.0	10.1	1,235.2	0.0	45,977.6

Table 12-73 shows there were 32,351.8 MW withdrawn from TC2. Table 12-73 presents totals by fuel type and projected in service date. Of the 32,351.8 MW withdrawn from TC2, 10,836.6 MW (33.5 percent) were thermal units.

Table 12-73 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year (withdrawn): September 30, 2025

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	107.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	399.9	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	539.9
2021	4,357.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	5,342.9	1,715.3	10.0	0.0	0.0	0.0	0.0	2,727.6	0.0	14,158.1
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	6,047.0	10,836.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	184.0	583.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	17,653.8
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	10,511.0	10,836.6	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	5,926.8	2,331.3	10.0	0.0	0.0	0.0	3.2	2,727.6	0.0	32,351.8

Analysis by Fuel Group

Table 12-74 shows the number of projects that entered TC2 by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). The 647 projects submitted to TC2 were made up of 389 renewable projects (60.1 percent), 190 storage projects (29.4 percent), 58 thermal projects (9.0 percent), five nuclear projects (0.8 percent) and five other fuel projects (0.8 percent).

Table 12-74 Transition cycle 2 and RRI number of projects by fuel group: September 30, 2025

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
2018	0	0.0%	1	100.0%	0	0.0%	0	0.0%	0	0.0%	1
2019	0	0.0%	2	100.0%	0	0.0%	0	0.0%	0	0.0%	2
2020	0	0.0%	18	72.0%	6	24.0%	0	0.0%	1	4.0%	25
2021	0	0.0%	363	69.5%	152	29.1%	4	0.8%	3	0.6%	522
2022	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2023	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2024	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2025	5	5.2%	5	5.2%	32	33.0%	54	55.7%	1	1.0%	97
Total	5	0.8%	389	60.1%	190	29.4%	58	9.0%	5	0.8%	647

As of September 30, 2025, there were 450 projects in TC2 in the status of active or under construction. Those 450 projects consisted of 288 renewable projects (64.0 percent of all projects and 53.2 percent of the nameplate MW), 111 storage projects (24.7 percent of all projects and 20.5 percent of the nameplate MW), 43 thermal projects (9.6 percent of all projects and 23.1 percent of the nameplate MW), five nuclear projects (1.1 percent of all projects and 3.3 percent of the nameplate MW) and three other fuel type projects (0.7 percent of all projects and .03 percent of the nameplate MW) (Table 12-75).

Table 12-75 Transition cycle 2 and RRI details by fuel group: September 30, 2025

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	5	1.1%	1,502.8	3.3%
Renewable	288	64.0%	24,442.2	53.2%
Storage	111	24.7%	9,404.9	20.5%
Thermal	43	9.6%	10,612.6	23.1%
Other	3	0.7%	15.1	0.0%
Total	450	100.0%	45,977.6	100.0%

Analysis by Unit Type and Project Classification

Table 12-76 shows the status of all new generation projects in TC2 by unit type and project classification as of September 30, 2025. Project classification is defined as either new generation or an uprate in which existing resources are modified to increase the economic maximum generation capability. There were 647 projects, representing 78,329.4 MW, entered into TC2. Of those, 647 projects, 197 projects, representing 32,351.8 MW (41.3 percent of the MW) withdrew prior to completion.

A total of 426 projects have been classified as new generation and 221 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 444 projects (68.6 percent) of all 647 generation projects to enter TC2.

Table 12-76 Transition Cycle 2 and RRI status of all generation projects: September 30, 2025

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	42	12	0	0	0	0	0	1	0	0	0	0	55	20	1	0	0	0	1	5	0	137
	Upgrade	37	3	0	0	1	0	0	0	0	0	0	0	15	4	0	0	0	0	0	0	0	60
Active	New Generation	63	7	1	0	0	0	0	1	1	0	0	0	177	33	0	0	0	0	1	5	0	289
	Upgrade	48	23	11	0	0	1	0	0	4	0	0	0	69	1	0	1	0	0	1	2	0	161
Total Projects	New Generation	105	19	1	0	0	0	0	2	1	0	0	0	232	53	1	0	0	0	2	10	0	426
	Upgrade	85	26	11	0	1	1	0	0	4	0	0	0	84	5	0	1	0	0	1	2	0	221

Table 12-77 shows the totals in Table 12-76 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 56.5 percent of all battery projects in TC2 classified as upgrades were active and 43.5 percent of battery projects classified as upgrades were withdrawn from TC2 as of September 30, 2025.

Table 12-77 Transition Cycle 2 and RRI status of all generation projects as a percent of total projects by classification: September 30, 2025

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT – Natural Gas	CT – Oil	CT – Other	Fuel Cell	Hydro – Pumped Storage	Hydro – Run of River	Nuclear	RICE – Natural Gas	RICE – Oil	RICE – Other	Solar	Solar + Storage	Solar + Wind	Steam – Coal	Steam – Natural Gas	Steam – Oil	Steam – Other	Wind	Wind + Storage	Total
In Service	New Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	New Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	40.0%	63.2%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	0.0%	0.0%	0.0%	0.0%	23.7%	37.7%	100.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	32.2%
	Upgrade	43.5%	11.5%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	17.9%	80.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	27.1%
Active	New Generation	60.0%	36.8%	100.0%	0.0%	0.0%	0.0%	0.0%	50.0%	100.0%	0.0%	0.0%	0.0%	76.3%	62.3%	0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	67.8%
	Upgrade	56.5%	88.5%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	82.1%	20.0%	0.0%	100.0%	0.0%	0.0%	100.0%	100.0%	0.0%	72.9%

Table 12-78 shows the total MW of projects in TC2 by unit type and project classification. For example, the 42 new generation battery projects that have been withdrawn from TC2 as of September 30, 2025, (as shown in Table 12-76) constitute 7,870.5 MW. The 55 new generation solar projects that have been withdrawn in the same time period constitute 5,265.2 MW.

Table 12-78 Transition cycle 2 and RRI status of all generation (MW) projects: September 30, 2025

		Project MW																					
Project Status	Project Classification	Battery	CC	CT – Natural Gas	CT – Oil	CT – Other	Fuel Cell	Hydro – Pumped Storage	Hydro – Run of River	Nuclear	RICE – Natural Gas	RICE – Oil	RICE – Other	Solar	Solar + Storage	Solar + Wind	Steam – Coal	Steam – Natural Gas	Steam – Oil	Steam – Other	Wind	Wind + Storage	Total
In Service	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	7,870.5	10,722.6	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	5,265.2	2,063.9	10.0	0.0	0.0	0.0	3.2	2,727.6	0.0	28,668.2
	Upgrade	2,640.5	114.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	661.7	267.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,683.6
Active	New Generation	7,078.2	8,507.6	700.0	0.0	0.0	0.0	0.0	14.0	859.0	0.0	0.0	0.0	14,893.1	3,795.0	0.0	0.0	0.0	0.0	10.1	1,167.2	0.0	37,024.1
	Upgrade	2,326.7	1,342.0	63.0	0.0	0.0	5.0	0.0	0.0	643.8	0.0	0.0	0.0	4,415.0	90.0	0.0	0.0	0.0	0.0	0.0	68.0	0.0	8,953.5
Total Projects	New Generation	14,948.7	19,230.2	700.0	0.0	0.0	0.0	0.0	19.3	859.0	0.0	0.0	0.0	20,158.2	5,858.9	10.0	0.0	0.0	0.0	13.3	3,894.8	0.0	65,692.3
	Upgrade	4,967.2	1,456.0	63.0	0.0	0.0	5.0	0.0	0.0	643.8	0.0	0.0	0.0	5,076.7	357.4	0.0	0.0	0.0	0.0	0.0	68.0	0.0	12,637.1

Table 12-79 shows the MW totals in Table 12-78 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 46.8 percent of all battery project MW in TC2 classified as upgrades were active and 53.2 percent of battery project MW classified as upgrades were withdrawn from TC2 as of September 30, 2025.

Table 12-79 Transition cycle 2 and RRI status of all generation projects as percent of total MW in project classification: September 30, 2025

		Percent of Total Projects by Classification																						
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	New Generation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	52.7%	55.8%	0.0%	0.0%	0.0%	0.0%	0.0%	27.3%	0.0%	0.0%	0.0%	0.0%	26.1%	35.2%	100.0%	0.0%	0.0%	0.0%	24.1%	70.0%	0.0%	43.6%
	Upgrade	53.2%	7.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	13.0%	74.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	29.1%
Active	New Generation	47.3%	44.2%	100.0%	0.0%	0.0%	0.0%	0.0%	72.7%	100.0%	0.0%	0.0%	0.0%	73.9%	64.8%	0.0%	0.0%	0.0%	0.0%	75.9%	30.0%	0.0%	56.4%
	Upgrade	46.8%	92.2%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	87.0%	25.2%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	70.9%

Cycle Process Totals[85]

On September 30, 2025, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 118,979.6 MW. On September 30, 2025, all projects in the cycle process queues were either in the status of active or were withdrawn. Table 12-80 shows each status by unit type. Of the 118,979.6 MW in the cycle process queues, 63,851.5 MW (53.7 percent) were active and 55,128.1 MW (46.3 percent) were withdrawn. Of the 63,851.5 MW in the status of active, 29,070.4 MW (45.5 percent) were solar projects, 5,612.5 MW (8.8 percent) were wind projects, and 11,659.1 MW (18.3 percent) were battery projects.

Table 12-80 All cycles (TC1, TC2 and RRI) project status (MW) by unit type: September 30, 2025

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	11,659.1	9,849.6	1,332.0	0.0	0.0	5.0	0.0	14.0	1,502.8	0.0	0.0	0.0	29,070.4	4,796.0	0.0	0.0	0.0	0.0	10.1	5,612.5	0.0	63,851.5
Withdrawn	14,539.2	10,836.6	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	17,094.5	5,528.5	209.0	0.0	0.0	0.0	3.2	6,911.9	0.0	55,128.1
Total	26,198.3	20,686.2	1,332.0	0.0	0.0	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	46,164.9	10,324.4	209.0	0.0	0.0	0.0	13.3	12,524.4	0.0	118,979.6

Table 12-81 shows that on September 30, 2025 there were 63,851.5 MW, on an energy basis, of which 40,975.1 MW are on a capacity basis that requested CIRs, in cycle process queues in the status of active or under construction. Table 12-81 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 40,975.1 MW, on a capacity basis that requested CIRs in the cycle process queues in the status of active or under construction, 16,320.0 MW (39.8 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

85 As of September 30, 2025, the cycle process totals include those projects included in TC1 and TC2.

Of the 15,133.8 MW, on a capacity basis that requested CIRs, of solar projects requested in cycle process queues in the status of active or under construction, 1,210.7 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 8,965.3 MW, on a capacity basis that requested CIRs, of battery projects requested in cycle process queues in the status of active or under construction, 5,199.9 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 19,887.0 MW, on a capacity basis that requested CIRs, of renewable projects requested in cycle process queues in the status of active or under construction, 2,044.2 MW (10.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Table 12-81 All cycles (TC1, TC2 and RRI) projects (active and under construction) by unit type adjusted for ELCC derates (MW): September 30, 2025

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	11,659.1	8,965.3	5,199.9
CC	9,849.6	9,495.9	7,027.0
CT - Natural Gas	1,332.0	1,307.0	797.3
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	5.0	5.0	4.6
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	14.0	14.0	5.5
Nuclear	1,502.8	1,305.9	1,240.6
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	29,070.4	15,133.8	1,210.7
Solar + Storage	4,796.0	3,378.8	270.3
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	10.1	9.1	6.5
Wind	5,612.5	1,360.4	557.8
Wind + Storage	0.0	0.0	0.0
Total	63,851.5	40,975.1	16,320.0

Surplus Interconnection Service (SIS)

FERC Order 845 required transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection.[86] Surplus interconnection service is defined as "any unneeded portion of interconnection service established in a large generator interconnection agreement (LGIA), such that if surplus interconnection service is utilized, the total amount of interconnection service at the point of interconnection would remain the same."[87] For example, a developer may request SIS to add a solar facility at the location of an existing battery storage facility. In this example, the battery storage facility operates at night only, while the solar facility operates during the day. The net output at the point of interconnection would never exceed the maximum facility output as

86 See *Reform of Generator Interconnection Procedures and Agreements, Order No. 845*, 163 FERC ¶ 61,043 (2018).
87 Id. At Pg. 373

studied for the existing battery storage facility's generation interconnection agreement.

Surplus interconnection service requests can be made by a project developer or one of its affiliates whose generating facility is already interconnected to the PJM transmission system or has executed (or requested to file unexecuted) an interconnection service agreement (ISA) or generation interconnection agreement (GIA), or by an unaffiliated project developer. The project developer, or one of its affiliates, has priority to use the service. However, if a project developer or affiliate does not submit a request for SIS, an unaffiliated project developer may request service. Under the SIS process, projects that do not trigger transmission system upgrades qualify for expedited review by PJM outside the interconnection queue. In order for a SIS request to be approved, no new network upgrades must be required to accommodate the request.[88]

If surplus interconnection service is requested on a generating facility that is an energy only resource, the generating facility requesting the SIS will also be an energy only resource. If surplus interconnection service is requested on a generating facility that is a capacity resource, the generating facility requesting surplus interconnection service may be an energy resource or a capacity resource, not to exceed the amount of CIRs established in the ISA or GIA. Requests for SIS are not posted publicly by PJM.

Interconnection Costs for New Projects

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[89] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. As part of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. Interconnection requests are for energy only resources and for capacity resources.

88 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 02 (July 23, 2025).
89 See OATT Parts IV & VI.

Interconnecting capacity resources must meet a higher standard than energy only resources. For interconnecting capacity resources, PJM performs deliverability studies that ensure that the energy from the proposed generator can be reliably provided to the PJM region. Deliverability studies identify network upgrades needed to ensure that the transmission system is capable of delivering the aggregate system generating capacity at peak load, including the new resource, with all firm transmission service modeled.[90] The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. In general, there are fewer network upgrades associated with energy only resources, as energy only resources are not required to be deliverable to the entire PJM footprint.[91] On September 30, 2025, there were 2,073 active network transmission upgrades. If a project is withdrawn from the queue, the network upgrades associated with that project are no longer required, unless it is required to support another queue project.

While not all projects in the queue require network upgrades, the number of planned network transmission upgrades is strongly correlated with the number of active projects in the queue. The number of planned network upgrades is also strongly correlated with the number of new generation projects requesting interconnection as a capacity resource. After the execution of an interconnection service agreement, queue projects become part of the RTEP study and the costs of any upgrade later necessary to preserve their Capacity Interconnection Rights are included as part of the overall transmission system costs paid by all transmission customers.

The system impact study is a detailed system analysis performed for new service requests that tests deliverability under peak load conditions and light load conditions. The system impact study identifies system constraints caused by the request and the local upgrades and network upgrades required to solve those constraints. The system impact study includes power flow analysis and short circuit analysis. The power flow analysis includes expected output level from the new resource under summer peak and light load system

90 See "PJM Manual 14B: PJM Regional Transmission Planning Process," Rev. 57 (September 25, 2024).
91 See "PJM Manual 14G: Generation Interconnection Requests," Rev. 8 (July 26, 2023).

conditions.[92] PJM's recent improvements to the deliverability analyses reflect more accurate information about the expected performance of intermittent resources, by type of resource (solar fixed, solar tracking, onshore wind and offshore wind), by season (summer, winter and light load) and by region (PJM West, Mid-Atlantic and Dominion), under each of these system conditions. Those modifications are necessary to accurately reflect the expected output of intermittent resources under various seasons and system conditions as the penetration and role of intermittents in PJM increases.[93] For example, the expected output of onshore wind varies from its maximum facility output to zero, depending on weather conditions, and the expected output levels are used for each system load condition.[94]

Capacity resources receive Capacity Interconnection Rights (CIRs) based on the deliverable MW which result from a combination of upgrades paid for by each project and existing system capability. Intermittent resources also require CIRs. The level of CIRs required for intermittent resources has been significantly understated because the required CIRs have been based on the derated capacity value of intermittents rather than the maximum energy injections required to achieve the derated value.

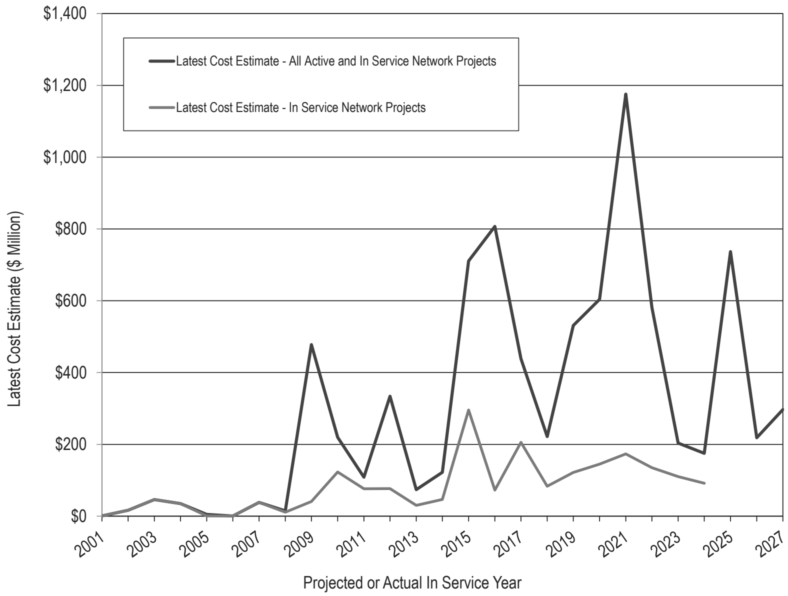
After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level.[95] Rules prior to the FERC order allowed generation at a level greater than the CIR value, and that was therefore not deliverable, to be inappropriately included in the ELCC calculations. For example, if a 100 MW solar resource has CIRs of 60 MW, generation in excess of 60 MW will not be included in the ELCC calculations under the updated rules. Prior to the update, the generation in excess of the CIR level was included, overstating the ELCC ratings and reliability contribution of ELCC resources. The overstatement of intermittent capacity has inefficiently suppressed capacity market clearing prices.[96] [97] In order to retain the prior, incorrectly calculated ELCC values, existing intermittent generating units are required to increase their CIRs by going through an expedited queue process. The ELCC updates established a transitional period during which intermittent generators can be awarded temporary increases in their CIRs based on the availability of transmission system capability.[98] PJM expects a transitional period of four years, beginning with the 2025/2026 Base Residual Auction, to be sufficient time for intermittent resources to reenter the queue and be awarded additional CIRs. New intermittent generators will be required to pay for CIRs consistent with their calculated reliability contribution.

Figure 12-5 shows the latest estimated interconnection costs for new generators (network transmission project cost) by projected and actual in service year for generators that are in service (red line), and for the total of generators in service and still in the queue in active status (blue line). The estimated costs for in service projects (red line) are much lower than the estimated costs that also include all projects in the queue (blue line). The increase in estimated total network upgrade costs for planned projects is a result of the large number of requests in the new services queue and the existing backlog (Figure 12-5). However, as generators withdraw from the queue, the overall network costs decrease. The estimated network upgrade costs for in service projects are much lower. The projected in service dates for network projects are not updated regularly, and therefore, may not be an accurate predictor of when these projects are actually expected to go in service. Figure 12-5 shows a significant level of estimated interconnection costs for resources with projected in service dates as far back as 2008 and a peak for projects with a projected in service date of 2021. Even the costs for projects that are in service are only estimates because PJM does not track final project costs. The final in service costs include only the last estimate provided by PJM before the project went in service. PJM's data collection, management and retention related to transmission spending of all types is inadequate and needs a significant upgrade. The failure to collect data on estimated and final project

92 Winter peak load is included in the generation deliverability powerflow analysis during the RTEP baseline reliability analysis, but is not currently performed for new interconnection requests. The light load analysis ensures generation deliverability during light load conditions, which is defined as 50 percent of the annual peak demand.
93 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).
94 See "Generation Deliverability Test Modifications: Light Load, Summer & Winter," presented at January 25, 2023 meeting of the Markets and Reliability Committee <https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230125/consent-agenda-c---1-generator-deliverability-test-revisions---presentation.ashx>.
95 183 FERC ¶61,009.
96 *See* "Analysis of the 2023/2024 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>. (October 28, 2022).
97 *See* "Analysis of the 2022/2023 RPM Base Residual Auction—Revised," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf> (January 13, 2023).
98 183 FERC ¶61,009 at 31.

costs makes it impossible to track transmission project costs for all project types. Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data.

Figure 12-5 Cost estimates of network projects by projected and actual in service year: January 1, 2001 through December 31, 2027



Regional Transmission Expansion Plan (RTEP)[99]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Managers approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated purpose of the market efficiency analysis is to: determine which reliability based enhancements have economic benefit if accelerated; identify new transmission enhancements that result in economic benefits; and identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. The PJM market efficiency analysis is badly flawed and results in concluding there are net benefits when there

99 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).

are not. PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over $50 million. PJM provides the review of a project with a projected cost of over $50 million using its own staff or outside consultants. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the benefit/cost ratio for the project. The benefit/cost ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission projects for years five through 15. This long-term proposal window takes place concurrently with the long-term proposal window for reliability projects.

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from November 1, 2016, through February 28, 2017. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board.

The fourth market efficiency cycle was performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on one internal and three interregional flowgates. PJM received 33 proposals from 10 entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.[100]

The fifth market efficiency cycle was performed for the 2020/2021 RTEP long term window. The 2020/2021 RTEP long term window was open from November 11, 2020, through May 11, 2021. This window accepted proposals to address historical congestion on four internal flowgates. PJM received 24 proposals from seven entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

100 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates.

The sixth market efficiency cycle was performed during the 2022/2023 RTEP long term window. The 2022/2023 RTEP long term window was delayed until the reliability violations for the 2022 Window 3 (Dominion data center loads) could be addressed. On November 21, 2023, PJM requested that the Commission grant a waiver to extend the time for PJM to complete its annual review of the benefit/cost analysis associated with the market efficiency cycle.[101] PJM requested the waiver to remain in effect until PJM completes its 2023 annual review no later than the end of the second quarter of 2024. On December 21, 2023, The Commission approved the waiver request.[102] In January 2024, PJM completed updating the 2022/2023 market efficiency base case to include the solution selected from the 2022 Window 3. No flowgates experienced historical congestion that required an open window.

In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. PJM posted an updated 2024/2025 base case in July 2024, and requested stakeholder feedback on three congestion drivers (Museville-Smith Mountain 128 kV in AEP, West Point-Laxena 115 kV in DOM and Garrett-Garrett Tap 115 kV in PN-APS) by August 31, 2024. The long term market efficiency window opened on April 11, 2025 and was closed on June 10, 2025. PJM received 14 proposals from (six proposals for Museville-Smith Mountain 128 kV, seven proposals West Point-Laxena 115 kV and one proposal for Garrett-Garrett Tap 115 kV) five entities. PJM is currently evaluating the proposals.

The Benefit/Cost Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a market efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. Depending on the type of project being evaluated PJM may measure benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market, but does not weight increases and decreases in benefits equally. There are significant issues with PJM's definition of benefits. If done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project.

The energy market benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in energy production costs and load energy payments.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project but, inexplicably, only for those zones where the project reduces the load payments and ignoring zones where the project increases load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but again only for those zones where the project reduces the load energy payments and ignoring zones where the project increases load payments.

In both the regional and subregional analysis, changes in zonal load energy payments subtract the estimated value of any Auction Revenue Rights (ARR) that sink in that zone. An increase in ARR revenues that result from a project

101 See *PJM Interconnection, L.L.C*, Docket No. ER24-477-000 (November 21, 2023).
102 185 FERC ¶61,212.

would reduce the benefits of that project to load. If done correctly and if ARRs returned 100 percent of congestion to load, the changes in load payments would equal the change in production costs. However, the calculated ARR credits in the benefit/cost analysis ignore any increases in ARR MW and include only the reduction in the estimated CLMP differences. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with the simulation's CLMP differences between ARR source and sink points. ARR MW are not adjusted to reflect any increase in ARR MW created by the RTEP upgrade. This means that the reduction in the ARR offset value is too large, the reduction in load payments is overstated, and the value of the proposed project is artificially increased.

The Reliability Pricing Model (RPM) Benefit analysis uses the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system wide total system capacity payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments.

The difference in the benefits calculation used in the regional and subregional benefit/cost threshold tests is related to how the direct costs of the transmission projects are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The allocation will be incorrect to the extent that the benefits calculations are incorrect.

There are significant issues with PJM's benefit/cost analysis. The current rules governing benefit/cost analysis of competing transmission projects do not correctly measure the relative costs and benefits of transmission projects. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments in the capacity market, but PJM's analysis ignores any increases in costs. This means that PJM's benefit/cost analysis systematically overstates the benefits of transmission projects. ARR MW allocations are not adjusted to reflect any potential changes in ARR MW that result from the RTEP upgrade. This means that the reduction in the ARR offset value is too large, the ARR offset is too small, and the result is to artificially increase the value of the proposed project. The correct metric is the change in production costs. In addition, the current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used, or for the fact that the project costs are nonbinding estimates, are not subject to cost caps and may significantly exceed the estimated costs. These flaws have contributed to PJM approving market efficiency projects with forecasted benefits that only appear to, but do not actually exceed the forecasted costs. In addition, there is no after the fact analysis to validate the planning assumptions and there is no data gathered on the actual costs and benefits that would permit such an analysis.

Recent proposals to use storage as a transmission asset (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. Storage is a market asset and should not be owned by transmission owners. PJM should not be evaluating SATA at all without a decision from FERC that SATA is allowable in PJM. At present it is not allowed. PJM's benefit/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. In addition, there is no basis for assuming anything about the actual use of a transmission storage asset and therefor any imputed benefits. Using a 15 year benefit horizon exaggerates the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established. Without clear rules on how to allocate operational revenues and costs, and without detailed information about exactly the storage would be used, it is impossible to develop forecasted benefits and/or costs of a SATA project.

The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. This is particularly noteworthy for the SATA case in which transmission owners would built market capacity assets under cost of service regulation that competes directly with market assets.

A significant flaw in PJM's benefit/cost analysis is that projected benefits are based on load forecasts which are currently dominated by projected large data center loads that are not verified by PJM and cannot be verified by PJM. That creates a bias towards finding transmission projects beneficial despite the fact that data center loads are imposing transmission costs on other customers as a result.

The MMU recommends that the market efficiency process be eliminated.

PJM MISO Interregional Market Efficiency Process (IMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.[103] The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM uses the benefit/cost analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members and under allocate costs to MISO members.

No interregional constraints were identified in either PJM's or MISO's regional processes. Therefore, an IMEP study was not required during the 2020/2021 IMEP cycle. No interregional constraints were identified in either PJM or MISO's regional processes. Therefore, an IMEP study was not required during the 2022/2023 IMEP cycle.

PJM and MISO began coordinating on interregional congestion issues to identify potential constraints to address in the 2024/2025 IMEP cycle. The

103 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

joint regional planning committee (JRPC) decided to not initiate a coordinated system plan in 2025, and will instead prioritize the interregional transfer capability study (ITCS).

PJM MISO Targeted Market Efficiency Process (TMEP)

PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than $20 million and must have estimated benefits, based on the projected congestion reduction over a four year period that exceed the expected installed capacity cost of the proposed project.[104] [105] The TMEP process calculates congestion and assigns congestion costs to load but fails to account for the offsetting value of ARRs and FTRs. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs. The correct benefit metric is the change in production costs.

The benefit of a proposed TMEP project is calculated as the value of reducing congestion on the affected constraint over a four year period. PJM and MISO calculate the estimated value of eliminating congestion by calculating the average congestion for the two prior years prior and multiplying by four. Congestion is correctly calculated as the shadow price (difference in CLMP) times the market flow on the line.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits, as calculated by PJM and MISO, received by that RTO.[106] The proportion of benefits is calculated using the change in the average shadow price of the constraint times the dfax to the affected downstream buses times the MW of load at the buses. This correctly identifies the proportion of the benefits that go to the load that would benefit from the project. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

PJM and MISO did not conduct a TMEP study in 2019. As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020. PJM and MISO agreed to assess the impact of planned upgrades and congestion using an additional year of market data. As a result, PJM and MISO did not conduct a TMEP study in 2021. The 2022 TMEP study focused on 23 flowgates as potential TMEP projects. Of the 23 initial flowgates, 19 were eliminated due to their relationship with other existing reliability projects already included in PJM's RTEP or MISO's MTEP plans, or the identified congestion was caused by outages.[107] Two projects were eliminated after studies showed that congestion was not persistent in October 2022, and an additional project was eliminated in December 2022 after further studies showed congestion was not persistent, leaving one TMEP project (Powerton - Towerline 138 kV) that was approved for implementation by the PJM Board on February 15, 2023, and by the MISO Board on March 23, 2023.[108] [109] [110] For both 2023 and 2024, the RTOs decided not to initiate a Coordinated System Plan (CSP) study, and to continue to assess the impact of planned upgrades and congestion persistence with additional market data.

PJM and MISO began coordinating on interregional congestion issues to identify potential constraints to address in the 2024/2025 TMEP cycle. The joint regional planning committee (JRPC) decided to not initiate a coordinated system plan in 2025, and will instead prioritize the interregional transfer capability study (ITCS). PJM and MISO are planning for an update in the winter of 2025.

104 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.
105 On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process. See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, et al. (November 2, 2017).
106 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

107 See "Interregional Planning Update," presented at the August 9, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220809/item-01---interregional-planning-update.ashx>.
108 See "Interregional Planning Update," presented at the October 4, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221004/item-01----interregional-planning-update.ashx>.
109 See "PJM-MISO IPSAC," presented at the December 15, 2022 meeting of the PJM-MISO Inter-regional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20221215/ipsac-presentation.ashx>.
110 See "PJM-MISO IPSAC," presented at the December 11, 2023 meeting of the PJM-MISO Inter-regional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2024/20240325/20240325-miso-seam-identified-issues-and-solutions-.ashx>

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total production cost of energy before and after the upgrade to all affected load. This measurement would include the change in expected LMP of all affected load before and after the upgrade, times the MW of load, plus the change in congestion dollars returned to the affected load before and after the upgrade. Congestion revenue returned to load is not a cost to the load, it is a credit against the overpayment of load payments compared to generation credits caused by the transmission constraint. Ignoring the return of congestion from ARRs/FTRs overstates the potential benefits of eliminating congestion through the TMEP upgrades, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

PJM MISO Interregional Transfer Capability Study (ITCS)

PJM and MISO are performing an Interregional Transfer Capability Study (ITCS).[111] PJM and MISO are coordinating assumptions and models, but will not perform a joint study. The PJM/MISO Interregional Transfer Capability Study is part of PJM's and MISO's strategy to comply with FERC Order No. 1920. The ITCS study appears to mirror PJM's multi driver RTEP process in that it identifies several drivers (efficiency, reliability, transfer needs) for evaluating the value or need for a project, though neither MISO nor PJM provide any specificity as to the exact metrics for the evaluation of the benefits or costs within each identified driver, how the drivers will be weighted or how costs of potential projects should be allocated. The stated purpose of the PJM/MISO Interregional Transfer Capability Study is to allow PJM and MISO to consider needs, assumptions, cost allocations and analysis outside the limits of the existing PJM/MIO JOA/CSP process. The goal of the PJM and MISO ITCS is to identify opportunities to enhance transfer capability on an incremental basis over and above other JOA/CSP based studies.

111 See PJM and MISO Interregional Capability Study (ICTS) FAQ <https://www.pjm.com/-/media/DotCom/planning/interregional-planning/pjm-and-miso-interregional-transfer-capability-study-faq.pdf>.

The ITCS study is intended to look out through 2032. In its ITCS study, PJM plans to use a model that blends MISO planning models for MISO's footprint and a set of PJM's long-term planning assumptions for PJM's footprint. PJM is calling this a blended model. PJM's blended model will use the 2023 Regional Transmission Expansion Plan (RTEP) topology with 2022 RTEP Window 3 solutions, the PJM 2024 official Load Forecast, retirements due to federal regulations and state laws based on the Independent State Agencies Committee (ISAC) workbook and the assumption of sufficient replacement generation or storage for resource adequacy (i.e. to meet 1-in-10 Loss of Load Expectation) selected from interconnection requests and withdrawals. Although it is a feature of many transmission planning studies, simply assuming specific generating assets is not a reasonable way to do transmission planning with significant cost impacts on customers.

Preliminary results from the ITCS study identified various transfer, reliability and economic issues from both PJM and MISO.[112] PJM and MISO presented results and near and long term actions resulting from the ITCS study on June 25, 2025.[113] Interregional constraints were identified in the 2024/2025 PJM and MISO's joint ITCS analysis.[114] MISO opened a proposal window for the identified MISO and MISO intertie constraints that closed in May of 2025. MISO received 34 unique proposals from eight entities. Based on these proposals MISO developed 54 potential solution ideas for further evaluation by PJM and MISO. PJM and MISO have stated that they do not have a defined project type (and related cost allocation) to address all of the issues/benefits for the solutions identified in the ITCS process. PJM is reviewing the MISO potential solutions to see if any of the proposals are captured in the PJM RTEP reliability, RTEP Market Efficiency and/or the M-3 (Supplemental) process. In the case of any overlaps between RTEP and ITCS, PJM will consider the ITCS needs in RTEP solutions. PJM and MISO are planning for an update in the winter of 2025.

112 See "PJM/MISO Interregional Transfer Capability Study," presented at the March 7, 2025 meeting of the PJM/MISO Interregional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250307/20250307-miso-pjm-ipsac-interregional-transfer-capability-study-itcs-to-pjm---working-draft.pdf>.
113 See PJM/MISO Interregional Transfer Capability Study (June 25, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250625/20250625-item-02---interregional-transfer-capability-study-update.pdf>.
114 See PJM/MISO Interregional Transfer Capability Study (June 25, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250625/20250625-item-02---interregional-transfer-capability-study-update.pdf>.

Multi Driver Process

On September 12, 2014, PJM filed revisions to the tariff to include provisions allowing PJM to include multi driver projects in its regional transmission expansion plan.[115] When a transmission project addresses a combination of reliability, market efficiency and/or public policy objectives, it is termed a multi driver project. PJM may choose a solution using either the proportional multi driver method or the incremental multi driver method. The proportional method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion project. The incremental method expands a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.[116] On February 20, 2015, the Commission approved the tariff revisions with an effective date of November 12, 2014.[117]

On June 7, 2022, PJM opened its first multi driver proposal window. The window seeks to address reliability and market efficiency needs on three identified facilities. PJM accepted proposed solutions until August 8, 2022. PJM received 14 proposals from three entities. After conducting a cost review, a reliability analysis and a market efficiency analysis on the 14 proposals and a combination of the proposals, PJM proposed a combination of two proposals made by two companies (Project 644 + 908) as its preferred solution. The preferred solution has an estimated capital cost of $82.30 million with a PJM determined expected benefit/cost ratio of 1.99.[118] PJM shared its recommendation with MISO for their evaluation. MISO did not indicate any concern with the proposed solution. On February 7, 2023, the PJM Board approved the recommended solution (Project 644 + 908).

The benefit/cost analysis used in the multi driver review is the same flawed benefit/cost analysis that PJM uses for evaluating Market Efficiency projects. PJM's assumed benefit of the combined project was calculated as the sum of the present value of positive (energy cost reductions to some loads) effects of $169.8 million. The sum of the present value of negative effects (energy cost increases to other loads), which was ignored in the PJM calculation of benefits, was $149.1 million. The total benefit of the proposed multi driver project is therefore only $20.7 million, not the $169.8 asserted by PJM, even ignoring the use of changes in congestion rather than changes in production costs. Using the total positive and negative effects to compare to the net present value of costs in the PJM's analysis, the benefit/cost ratio is 0.24, not 1.99. All $149.1 million of the increases in energy costs (negative benefits) would be paid by load in the ComEd Zone. Based on the requirement of benefit/cost ratio of 1.25, the energy efficiency portion of the multi driver project should have been rejected.

State Agreement Approach (SAA)

PJM's State Agreement Approach (SAA) is a provision in PJM's Operating Agreement that allows states to propose transmission projects for inclusion in PJM's Regional Transmission Expansion Plan if the state agrees to assume the full cost of the proposed transmission projects. The purpose of the SAA is to allow states to pursue their public policy goals without imposing costs on other states. The SAA can also be used by a group of states that agree to a transmission project as part of a collaborative goal. Under the SAA, a state can elect to select the entity to complete the project or the states can request that PJM open a competitive window to seek transmission solutions from developers that address the required upgrades. SAA projects are classified as public policy baseline projects or as a supplemental project developed by the selected PJM Transmission Owner. The state decides whether to pursue a project that comes out of the SAA process.

Five states (Delaware, Maryland, North Carolina, Virginia and New Jersey) made a joint request to PJM to conduct a two phase study (The Offshore Wind Transmission Study) to determine reinforcements to the onshore grid to reliably deliver 6,416 to 17,016 of offshore wind plus additional RPS target requirements.[119] The phase one study, published on October 19, 2021, examined, at a high level, enhancements to the existing infrastructure needed to reliably integrate the proposed offshore wind generation, but did not

115 See PJM. Docket No. ER14-2864 (September 12, 2014).
116 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).
117 150 FERC ¶ 61,117 (February 20, 2015).
118 See "2022 RTEP Multi-Driver Proposal Window No. 1," presented at the December 6, 2022 meeting of the Transmission Expansion Advisory Committee <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221206/item-07---multi-driver-proposal-window-update.ashx>.
119 See Offshore Wind Transmission Study: Phase 1 Results, October 19, 2021 <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.pdf>.

include any estimates of the costs of the transmission infrastructure needed. The phase 1 study did not consider any greenfield transmission solutions, instead using existing facilities as potential points on injection (POI) and existing transmission paths as locations for upgrades. The study considered six scenarios.

Scenario 1 focused on a short term window that assumed a wind injection total of 6,416 MW and RPS targets through 2027 with a projected cost of $627 million. Scenario 1 included generator deactivations that were announced as of October 1, 2020, and were included in PJM's RTEP base case that formed the basis of the study. The other scenarios (Scenario 2 through Scenario 6) were longer term studies that looked out through 2035. Scenario 2, with a projected cost of $2,461.4 million, assumed 14,416 of offshore wind capacity and the same generator deactivations assumed in Scenario 1. Scenarios 2 through 6 assumed 1,739 MW of additional deactivated generation in addition to what was modeled in Scenario 1 and 2. Scenario 3 was abandoned due to legislation being withdrawn that had required the retirement of specific units. Scenario 4 assumed an increase (relative to Scenario 1) of 2,600 MW additional offshore wind connecting to Virginia POI resulting in projected costs of $3,213.1 million in needed upgrades. Scenario 5 assumed a different POI for Scenario 1 New Jersey offshore wind and cost $2,591.8 million in expected upgrade costs. Scenario 6 removed 2,000 MW of New Jersey offshore wind from Scenario 2 resulting in $2,164.3 million in projected upgrade costs.

The states decided to not pursue a joint Phase 2 study.

New Jersey State Agreement Approach for Offshore Wind

In 2021, the New Jersey Board of Public Utilities (NJ BPU) initiated a proposal window under the SAA to meet New Jersey's goal of interconnecting up to 7,500 MW of offshore wind.[120] PJM received 80 proposals covering solutions that addressed onshore and offshore reliability criteria and transmission connections. The NJ BPU selected a proposal to interconnect 3,742 MW of offshore wind to central New Jersey at a total estimated cost for the project of $1.1 billion, with in service dates from December 2027 through June 2030. The costs for the NJ BPU offshore wind project will be recovered from customers in the state of New Jersey. On December 6, 2022, the PJM Board approved the BPU's proposal.

On September 22, 2023, Public Service Electric and Gas Company filed an application for an abandoned plant incentive.[121] The filing seeks "authorization for the ability to recover 100 percent of prudently incurred costs for certain transmission upgrades that PSE&G will construct in the event that the [offshore wind] transmission upgrades are abandoned or cancelled (in whole or in part) for reasons that are outside of PSE&G's control."

On October 31, 2023, Danish wind power developer Ørsted announced that it was canceling two major offshore wind projects, Ocean Wind 1 (1,100 MW) and Ocean Wind 2 (1,148 MW), that were planned off the coast of New Jersey. Ørsted is taking a $2.9 billion impairment attributed to Ocean Wind 1.[122] On September 30, 2025, only nine offshore wind projects remained in the combined serial and cycle queues.

Maryland State Agreement Approach (SAA) for Offshore Wind

On December 5, 2024, the Maryland Public Service Commission (MD PSC) requested that PJM conduct analysis of Maryland's 8,500 MW off shore wind target, assuming three different POI scenarios, in response to the Maryland POWER Act of 2023. PJM provided the requested study on March 21, 2025.[123] On June 23, 2025, the Maryland Public Service Commission requested that PJM issue a competitive solicitation for proposals under the SAA process for onshore injection of 2,000 MW offshore wind at Indian River by 2028 (DP&L), 1,500 MW of offshore wind at Cool Spring by 2030 (DP&L), 1,500 MW of offshore wind at Piney Grove by 2030 (DP&L), 1,500 MW of offshore wind at Nelson by 2030 (DP&L) and 2,000 MW of offshore wind at Calvert Cliff by 2031 (PEPCO).[124] PJM is currently working with the MD PSC to draft a SAA

120 See PJM Operating Agreement, Schedule 6, Section 1.5.9

121 See *Public Service Electric and Gas Company*, Docket No. ER23-2916 (September 22, 2023).

122 Ørsted, Ørsted ceases development of its US offshore wind projects Ocean Wind 1 and 2, takes final investment decision on Revolution Wind, and recognises DKK 28.4 billion impairments (October 31, 2023) <https://orsted.com/en/company-announcement-list/2023/10/oersted-ceases-development-of-its-us-offshore-wind-73751>.

123 See Maryland Offshore Wind Information Study Results, March 21, 2025 <https://webpscxb.psc.state.md.us/DMS/case/9800>.

124 See Maryland PSC Request Letter, June 23, 2025 <https://webpscxb.psc.state.md.us/DMS/case/9800>.

study agreement, which must be filed and approved by the Federal Energy Regulatory Commission (FERC). The goal is to have PJM open a competitive window in 2026 for the proposed requirements.

Long Term Regional Transmission Planning

On May 13, 2024, the Commission issued Order No. 1920 which requires public utility transmission providers to engage in long-term regional transmission planning over a 20-year planning horizon, develop long-term scenarios to identify long-term transmission needs and enable the identification and evaluation of transmission facilities to meet those transmission needs. Order No. 1920 also requires transmission providers to determine a cost allocation method for long-term regional transmission facilities, make other reforms to enhance transparency in local transmission planning, to correctly size transmission projects and include interregional transmission coordination to support the development of cost-effective projects.[125]

On November 21, 2024, the Commission issued Order No. 1920-A.[126] Order No. 1920-A significantly expanded the role of States in the long-term regional transmission planning. Order No. 1920-A requires states' input into regional transmission planning and cost allocation processes, both in the transmission providers' development of Order No. 1920 compliance filings and the ongoing implementation of these reforms in the future. Order No. 1920-A also increases the states' role in: (i) developing long term scenarios; (ii) requesting additional scenarios beyond the three Long-Term Scenarios required by Order No. 1920; (iii) developing the evaluation processes and criteria for selecting new transmission facilities in the long-term regional transmission; (iv) developing cost allocation approaches for selected transmission facilities; and (v) voluntary funding opportunities.

PJM requested that the Commission extend PJM's deadline to comply with Order No. 1920's compliance directives by six months, (to December 12, 2025), while leaving the implementation deadline of two years after the initial due date of the compliance filing (June 12, 2027) unchanged. The extension was requested to accommodate the States' broader role required by Order No. 1920-A in developing Order No. 1920-compliant Long-Term Regional Transmission Planning protocols.[127]

Supplemental Transmission Projects

Supplemental projects are asserted to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[128] Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan.

The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted in the Local Plan is the Transmission Owner's decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM's Regional Transmission Expansion Plan and are allocated 100 percent to the zone in which the transmission facilities are located. Supplemental Projects may displace projects that would have otherwise been implemented through the RTEP process.

Supplemental projects are currently exempt from the Order No. 1000 competitive process.[129] Transmission owners have a clear incentive to increase

125 See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order No. 1920*, 187 FERC ¶ 61,068 (2022).
126 See *Order on rehearing and clarification, Order No. 1920-A*, 189 FERC ¶ 61,126 (2024).
127 See PJM Interconnection, L.L.C., Docket No. RM21-17-000 (December 20, 2024).
128 See PJM. Planning. "Transmission Construction Status," (Accessed on September 30, 2025) <https://www.pjm.com/planning/project-construction>.
129 FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-6 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. Baseline projects are RTEP projects needed for reliability. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No. 890, there were transmission projects planned by transmission owners and included in the PJM planning models that were not included in the totals shown in Figure 12-6, Table 12-82 and Table 12-83 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

PJM's data collection, management and retention related to transmission spending of all types is inadequate and needs a significant upgrade. The failure to collect data on estimated and final project costs makes it impossible to track transmission project costs for all project types. Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data.

Figure 12-6 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through December 31, 2025

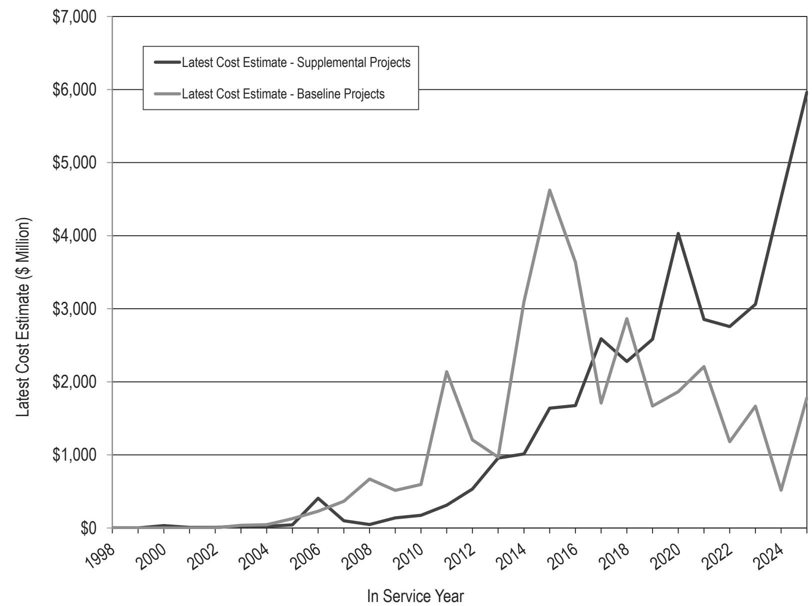


Table 12-82 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 1,110.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 242 for years 2008 through 2025 (post Order No. 890). As of September 30, 2025, there were 2,073 supplemental projects with expected in service dates between January 1, 2025 and December 31, 2036.

Table 12-82 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	0	2	0	0	1	0	0	0	0	0	0	0	0	3
2000	0	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0	0	0	0	0	0	0	0	11
2001	0	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	10
2003	3	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	0	2	0	40
2005	4	2	0	8	0	0	4	0	0	0	1	14	0	1	0	0	0	1	2	0	0	2	0	39
2006	4	2	0	5	0	0	6	0	0	0	0	9	0	1	0	0	0	0	1	0	2	1	0	31
2007	1	1	0	5	0	4	5	0	0	4	0	6	0	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	0	3	1	0	41
2009	3	1	0	6	0	1	8	0	0	3	3	5	0	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	0	7	0	3	4	0	0	6	3	0	0	1	2	0	0	2	0	0	3	5	0	42
2011	0	8	0	8	0	0	2	0	0	5	2	0	0	1	0	0	0	4	0	0	7	4	0	41
2012	0	5	0	6	4	1	2	0	7	3	16	1	0	2	0	0	0	1	0	0	6	11	0	65
2013	5	21	0	4	5	0	11	0	6	4	13	1	0	1	1	0	0	1	0	1	14	19	0	107
2014	2	31	0	2	8	2	14	0	5	6	18	3	3	2	0	0	0	1	2	0	10	15	0	124
2015	4	15	0	2	9	1	37	0	8	4	17	5	3	2	0	0	0	1	0	4	7	22	0	141
2016	6	17	0	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	29	0	146
2017	8	107	0	3	26	1	23	0	3	8	31	11	5	0	3	0	0	0	3	1	22	43	0	298
2018	10	143	0	3	13	1	20	0	14	3	22	6	4	0	0	0	0	2	0	1	20	25	0	287
2019	3	163	0	4	30	5	14	2	16	1	33	8	5	3	14	0	0	1	15	0	15	27	0	359
2020	5	132	0	4	35	6	12	7	13	1	30	2	6	9	17	0	0	3	33	1	17	23	0	356
2021	4	155	0	6	30	8	4	5	13	2	22	0	8	17	22	0	0	22	24	0	19	23	0	384
2022	1	152	0	10	31	5	10	6	9	1	28	2	6	14	34	0	0	5	29	0	18	17	0	378
2023	5	186	0	17	19	10	6	4	9	1	35	4	6	5	20	2	0	5	12	5	15	20	0	386
2024	7	266	1	27	28	11	8	18	3	0	32	4	10	17	26	0	0	9	23	8	16	16	0	530
2025	3	299	3	14	36	10	6	17	13	3	41	0	7	27	46	0	0	5	56	8	19	17	0	630
2026	0	160	3	24	22	8	18	15	11	2	43	3	5	23	30	0	0	2	30	1	24	8	0	432
2027	4	147	5	31	31	0	9	16	6	3	25	2	7	20	18	0	5	3	14	3	40	19	0	408
2028	4	130	1	16	16	4	5	5	5	0	13	2	2	15	3	0	0	5	9	4	12	8	0	259
2029	8	76	0	16	4	0	0	4	4	0	8	2	3	2	2	0	0	1	1	1	8	9	0	149
2030	4	70	1	0	3	0	0	3	0	0	6	0	0	2	0	0	0	0	0	4	7	0	0	100
2031	1	44	0	0	2	3	0	0	2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	53
2032	2	7	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12
2033	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	16	0	0	18
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	4	0	0	10
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	109	2,348	14	261	369	85	269	102	153	64	462	160	82	167	241	2	5	82	267	45	337	374	0	5,998

Table 12-83 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 3,156.0 percent, from $64.5 million for years 1998 through 2007 (pre Order No. 890) to $2.1 billion for years 2008 through 2025 (post Order No. 890). As of September 30, 2025, the 1,878 supplemental projects with expected in service dates between January 1, 2025 and December 31, 2029, have a total cost estimate of $25.3 billion.

Table 12-83 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.99
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.66	$0.00	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.98	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.91
2006	$4.03	$309.70	$0.00	$0.93	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.14
2007	$0.56	$2.06	$0.00	$9.85	$0.00	$37.61	$4.64	$0.00	$0.00	$31.75	$0.00	$9.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.80
2008	$2.36	$0.00	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.59	$0.00	$0.00	$47.32
2009	$0.77	$0.90	$0.00	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.35	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.66
2010	$0.00	$34.36	$0.00	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$0.00	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$0.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$0.00	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$0.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.72	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$305.30	$0.00	$1,012.86
2015	$3.73	$237.45	$0.00	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.22	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$721.91	$0.00	$1,640.02
2016	$74.54	$84.13	$0.00	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$0.00	$86.40	$0.40	$7.80	$58.76	$742.48	$0.00	$1,675.74
2017	$66.28	$648.74	$0.00	$8.60	$164.45	$0.09	$145.97	$0.00	$64.31	$3.62	$104.25	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
2018	$66.55	$816.23	$0.00	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$537.85	$0.00	$2,278.99
2019	$64.30	$1,114.64	$0.00	$11.97	$190.40	$76.55	$90.19	$0.30	$90.69	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,582.11
2020	$59.58	$920.44	$0.00	$0.30	$115.41	$62.58	$78.09	$14.36	$72.06	$6.40	$258.72	$39.50	$25.61	$2.30	$23.10	$0.00	$0.00	$2.40	$72.70	$102.70	$215.29	$1,959.38	$0.00	$4,030.92
2021	$86.54	$1,192.02	$0.00	$9.50	$184.21	$32.52	$140.90	$17.79	$117.39	$18.90	$98.40	$0.00	$25.67	$47.84	$85.89	$0.00	$0.00	$73.40	$63.48	$0.00	$197.67	$460.84	$0.00	$2,852.96
2022	$81.40	$779.31	$0.00	$19.32	$205.52	$190.13	$147.60	$21.46	$64.32	$45.00	$194.60	$9.38	$22.12	$34.84	$127.04	$0.00	$0.00	$72.80	$59.79	$0.00	$231.92	$450.83	$0.00	$2,757.38
2023	$59.10	$851.33	$0.00	$49.09	$160.41	$18.35	$48.34	$25.60	$112.27	$0.00	$333.30	$87.57	$29.77	$3.41	$130.50	$68.77	$0.00	$24.40	$20.07	$218.84	$191.73	$628.26	$0.00	$3,061.11
2024	$87.60	$1,823.87	$20.00	$69.91	$199.70	$23.84	$219.60	$202.60	$31.73	$0.00	$494.82	$95.30	$61.42	$89.13	$103.80	$0.00	$0.00	$173.57	$64.68	$5.54	$235.95	$517.54	$0.00	$4,520.60
2025	$54.08	$2,121.03	$27.00	$154.55	$569.33	$141.20	$156.60	$77.60	$113.68	$46.55	$507.30	$0.00	$51.08	$141.02	$186.82	$0.00	$0.00	$39.29	$178.56	$595.10	$351.70	$448.63	$0.00	$5,961.12
2026	$0.00	$1,493.71	$32.74	$230.55	$276.23	$405.92	$711.70	$118.66	$125.23	$0.00	$1,249.84	$69.18	$19.87	$117.38	$160.06	$0.00	$0.00	$50.20	$59.54	$0.50	$457.40	$330.90	$0.00	$5,909.61
2027	$91.70	$1,340.57	$47.00	$215.42	$577.57	$0.00	$452.00	$129.51	$60.15	$168.50	$735.50	$14.10	$87.35	$188.13	$149.53	$0.00	$4.40	$47.20	$126.67	$2.04	$789.18	$685.20	$0.00	$5,911.72
2028	$100.19	$1,113.01	$15.30	$115.14	$407.55	$491.55	$540.90	$33.80	$42.35	$0.00	$370.15	$68.00	$26.88	$82.74	$104.50	$0.00	$0.00	$54.40	$250.20	$3.24	$323.56	$497.78	$0.00	$4,641.24
2029	$154.81	$449.03	$0.00	$137.56	$74.82	$0.00	$0.00	$46.20	$84.43	$0.00	$718.42	$37.50	$49.90	$14.30	$26.40	$0.00	$0.00	$82.00	$138.00	$0.50	$267.00	$638.50	$0.00	$2,919.37
2030	$220.20	$395.89	$29.00	$0.00	$43.60	$0.00	$0.00	$74.30	$0.00	$0.00	$123.50	$0.00	$0.00	$10.02	$0.00	$0.00	$0.00	$0.00	$0.00	$22.00	$39.75	$0.00	$0.00	$958.26
2031	$31.50	$488.59	$0.00	$0.00	$423.70	$276.00	$0.00	$0.00	$11.00	$0.00	$0.00	$42.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,273.29
2032	$84.00	$285.05	$0.00	$5.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$374.43
2033	$0.00	$0.00	$0.00	$1.90	$0.00	$0.00	$0.00	$0.00	$0.00	$30.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$242.17	$0.00	$0.00	$274.47
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$443.00	$0.00	$89.40	$0.00	$0.00	$532.40
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$166.60	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$166.60
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,420.93	$17,288.85	$171.04	$1,154.76	$3,932.35	$1,810.17	$3,717.26	$762.18	$1,127.08	$569.40	$5,992.27	$812.60	$438.61	$751.76	$1,185.69	$68.77	$4.40	$1,031.56	$1,576.32	$1,171.16	$4,651.61	$11,088.46	$0.00	$60,727.23

On September 28, 2023, the Office of Ohio Consumers' Counsel filed a complaint regarding the impact of the volume and costs of supplemental projects on consumers. The complaint requests that the Commission develop a mechanism, to be included in the PJM Tariff and Operating Agreement, whereby "FERC would review the need, prudence and cost-effectiveness of local transmission projects in Ohio." The complaint also requests the Commission to appoint an Independent

Transmission Monitor (ITM) to assist "in reviewing the planning, need, prudence and cost-effectiveness of local transmission projects for consumers in Ohio", and to "consider precluding the Ohio Transmission Utilities from using formula rates for establishing transmission rates."[130] The Office of Ohio Consumers' Counsel's complaint is pending.

On December 19, 2024, a group of consumer interests filed against multiple transmission owners and RTOs/ISOs.[131] The complaint alleges that provisions in the tariffs of the transmission owning utilities and the RTOs/ISOs inappropriately authorize individual transmission owners to plan facilities rated at 100 kilovolts kV and above without regard to efficiency or cost-effectiveness. The complaint does not challenge the rates for any specific locally planned projects, but, rather, alleges that the cumulative effect of tariff provisions allowing local planning of transmission projects rated at 100 kV and above results in unjust and unreasonable transmission rates.[132] The complaint requests issuance of an order that, for transmission facilities rated at 100 kV and above, requires: (i) removal of planning from transmission owner tariffs (and RTO tariffs that confirm such transmission owner planning); (ii) amendment of regional planning tariffs to require that all planning be done at the regional or interregional level (specifying facilities reaching the end of operational life); and (iii) amendment of regional planning tariffs be to require that the regional planning within the existing Order No. 1000 regions be conducted by independent transmission system planners.[133] The complaint recommends that independent transmission planners be structured similar to independent market monitors or be included in an expanded market monitoring function.[134] The consumer interests' planning complaint is pending.

The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated.

130 See Office of the Ohio Consumers' Counsel v. PJM, et al., Docket No. EL23-105 (September 28, 2023).
131 See Industrial Energy Consumers of America v. PJM, et al., Docket No. EL25-44-000 (December 19, 2024).
132 *Id.* at 11.
133 *Id.* at 42–43.
134 *Id.*, Attachment C (Declaration of Michael A. Giberson) at 36:11–37:8.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[135]

The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build such projects.

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project types include:

- **Immediate Need Exclusion.** If the violation needs to be resolved within three years or less, all such projects are excluded from competition. The local Transmission Owner is the Designated Entity.[136]

  On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission's directives under Order 1000.[137] Some supplemental projects are in this category. In a decision issued August 19, 2022, the U.S. Court of Appeals for the D.C Circuit found that FERC reasonably approved MISO's Immediate Need Reliability Exception.[138] The Court rejected arguments challenging the MISO rule because (i) the definition of projects eligible for the exception was insufficiently limited and (ii) the rule allows for designating the incumbent

135 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).
136 See OA Schedule 6 § 1.5.8(m).
137 169 FERC ¶ 61,054 (2019).
138 LSP Transmission Holdings II, LLC v. FERC, 45 F.4th 979.

developer before posting of the basis for the exception.[139] The decision was largely based on deference to FERC expertise.[140]

- **Below 200kV.** All projects at voltages less than 200kV are excluded from competition. The local Transmission Owner is the Designated Entity.[141] Some supplemental projects are in this category.
- **Substation Equipment.** If the limiting element(s) is substation equipment, such projects are excluded from competition. The local Transmission Owner is the Designated Entity.[142] Some supplemental projects are in this category.

While the PJM Operating Agreement defines the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. The MMU recommends that rules be implemented to require competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition for any of these exclusion categories.

Dominion Data Center Alley Immediate Need and Long Term Solution

Dominion presented 44 supplemental project requests to serve new data center load through the summer of 2025. PJM identified the need for additional baseline reinforcements to support the load growth. Rather than a competitive process, PJM decided to designate the upgrades as immediate need and allowed Dominion to construct these lines.[143] [144]

The 2022 RTEP Window 3 addressed long term reliability needs as well as the additional baseline reinforcements for Data Center Alley. The proposal window was open from February 24, 2023, to May 31, 2023, and received 72 submissions from 10 entities. The cost estimate for the total scope of work was $5.1 billion, $1.4 billion of which was for the necessary baseline upgrades specific to the Data Center Alley reinforcements.[145] The proposed Data Center Alley solution includes 500kV and 230kV lines extensions, the reconductoring of multiple 230kV lines and substation work.[146]

On December 8, 2023, the Maryland Office of People's Counsel (MDOPC) submitted a letter to the PJM Board.[147] The letter requested that the PJM Board defer the December 11, 2023, vote on the 2022 RTEP Window 3 proposal. The MDOPC letter cited concerns regarding the scale, scope and cost of the proposal. Additionally, the MDOPC expressed concerns that "the current failure to unpack the relative contribution of each of the "drivers" of the need for the W3 projects makes it impossible for the public to understand how cost causation principles apply to the projects." On December 11, 2023, the PJM Board approved the recommended solution. PJM filed the RTEP on January 10, 2024, and the Commission accepted it by order issued April 8, 2024.[148]

Comparative Cost Framework

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[149]

139 *Id.* at 999.
140 *Id.*
141 See OA Schedule 6 § 1.5.8(n).
142 See OA Schedule 6 § 1.5.8(p).
143 See "Dominion Northern Virginia Area Violations," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia-area-violations---need-statement.ashx>.
144 See "Dominion Northern Virginia Area Immediate Need," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia---immediate-need.ashx>.
145 See "*Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board*," December 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx>.
146 See "*Reliability Analysis Report: 2022 RTEP Window 3*," December 8, 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx>.
147 See "MD Office of People's Counsel Letter regarding 2022 RTEP Window 3 Procurement," <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20231208-pjm-board-letter-2023-12-08-md-opc-final.ashx>.
148 See 187 FERC ¶ 61,012. Maryland Office of the People's Counsel filed a protest, which the Commission determined was outside of the scope of the RTEP filing.
149 See 170 FERC ¶ 61,243 (2020).

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. PJM has not provided the requested data to the MMU to allow for an analysis of their financial review process. Without this data and analysis, the MMU cannot verify that the analysis performed under the comparative cost framework was sufficient or adequately followed the process defined in the PJM manual.[150] The existing proposal templates do not provide enough information to adequately perform a financial analysis. The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee considered whether storage devices should be included in the RTEP process as transmission assets.[151] On February 24, 2021, the Markets and Reliability Committee (MRC) voted to defer endorsement of governing document language associated with Storage as a Transmission Asset in reliability planning. The MRC chose to defer the language until a comprehensive proposal addressing all aspects of incorporation of storage resources into markets, operations and planning.

Transmission and generation have, and have always had, a symbiotic relationship in the provision of wholesale power. Transmission needs generation to function and generation needs transmission to function. Transmission can substitute for generation at the margin and generation can substitute for transmission at the margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost of service recovery through AEP's formula rates.[152] AEP's Middle Creek energy storage project was a proposed battery storage device that would discharge energy to serve retail load at the Middle Creek substation in the event of a transmission outage. On December 21, 2020, the Commission ruled that the Middle Creek energy storage project did not perform a transmission function, and was ineligible to recover its costs through formula rates.[153]

Storage devices like batteries that are defined to be part of PJM markets should not be treated as transmission assets. These devices should be treated as market assets. The MMU recommends that storage resources not be includable as transmission assets for any reason.

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[154]

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

150 See "PJM Manual 14F: Competitive Planning Process," Rev. 10 (October 30, 2024).
151 See PJM. "*Storage As A Transmission Asset: Problem / Opportunity Statement*," <https://pjm.com/-/media/committees-groups/committees/pc/2020/20200605-special/20200605-item-02a-storage-as-a-transmission-asset-problem-statement-clean.ashx>.
152 See *AEP*, Docket No. EL20-58 (July 22, 2020).
153 173 FERC ¶ 61,264 (2020).
154 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

In the first nine months of 2025, the PJM Board approved a net change of $7.9 billion in transmission upgrades. As of September 30, 2025, the PJM Board had approved $58.0 billion in transmission system enhancements since 1999.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system, financed and built by market participants, that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions.

If a QTU that was cleared in a Base Residual Auction (BRA) or Incremental Auction (IA) is not completed by the start of the Delivery Year, the submitting party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2025, no QTUs have cleared a BRA or IA.

Cost Allocation

Required transmission enhancements are categorized as: supplemental, network or baseline upgrades. The cost allocation of the transmission enhancements depends on the category of upgrades.

Supplemental Upgrade Cost Allocation

Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[155] Supplemental projects are exempt from competition. The costs of supplemental projects are allocated 100 percent to the zone in which the transmission facilities are located.[156]

155 See PJM. "Transmission Construction Status," (Accessed on September 30, 2025) <https://www.pjm.com/planning/m/project-construction>.
156 See OATT Schedule 12(a)(iii).

Network Upgrade Cost Allocation

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[157] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process assigns the upgrade costs to the project or projects that are causing the costs to be incurred. As part of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. For required network upgrades under the new cluster based service request cycles, the costs of the network upgrades are assigned to individual projects that caused the costs to be incurred.[158]

Baseline Upgrade Cost Allocation

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. Typically, load growth creates conditions that may create violations of reliability criteria, which in turn require upgrades. The PJM RTEP identifies necessary upgrades to remain compliant with national and regional reliability standards. These modifications are baseline upgrades. Baseline upgrades can also include market efficiency projects.

The costs of regional baseline facilities are allocated 50 percent on a load-ratio share and 50 percent on a directionally weighted solution based DFAX method.[159]

157 See OATT Parts IV & VI.
158 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 02 (July 23, 2025).
159 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024) for a complete explanation of the directionally weighted solution based DFAX method.

The costs of the necessary lower voltage facilities required to support the regional baseline facilities with estimated costs greater than or equal to $5 million are assigned on a directionally weighted solution based DFAX method.

The costs of the necessary lower voltage facilities required to support the regional baseline facilities with estimated costs below $5 million are assigned to the zone where the upgrade is located.

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[160] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[161]

The issues identified in the complaints and at the technical conference included: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

On February 20, 2020, the Commission issued an Order denying rehearing requests.[162] The Commission found that PJM's solution based dfax method for regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable.

160 153 FERC ¶ 61,245 at P 35 (2015).
161 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
162 See 170 FERC ¶ 61,122 (2020).

On appeal, the U.S. Court of Appeals for the D.C. Circuit in 2022 found that FERC had failed to explain its distinction between the projects eligible to use the dfax method and those not eligible.[163] The Court objected that without adequate explanation: "The Bergen project 'addresses a non-flow related reliability issue,' just like the non-flow-based stability issue in Artificial Island, but FERC had treated the two projects differently."[164] The Court also rejected the 0.01 distribution cutoff factor as "absurd."[165] The Court remanded issues concerning PJM's solution based dfax method to FERC, where the matter is now pending.[166]

It is clear that the allocation issues are difficult. Nonetheless, allocation methods affect the efficiency of the markets. Allocation methods also affect the degree to which transmission upgrades required to serve data center load are allocated to other customers. The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives are thoroughly reviewed.

As an example, the use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

163 See *Consolidated Edison v. FERC et al.*, 45 F.4th 265 (D.C. Cir. August 9, 2022).
164 *Id.* at 9.
165 See *id.*
166 See FERC Docket Nos. EL21-39-000, et al.

Transmission Line Ratings

Transmission line ratings, and more broadly transmission facility ratings, are the metric for the ability of transmission lines to transmit power from one point to another. Transmission line ratings have significant and frequently underappreciated impacts on competitive wholesale power markets like PJM. Line ratings directly affect energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the costs for the interconnection of new power plants. The impact of transmission facility ratings on markets is a function both of the line ratings directly and the use of those ratings by the RTO/ISO.

Congestion payments by load result when lower cost generation is not available to meet all the load in an area as a result of limits on the transmission system. When higher cost local generation is needed to meet part of the local load because of transmission limits, 100 percent of the local load pays the higher price while only the local generation receives the higher price. The difference between what the load pays and generators receive is congestion. Since 2008, congestion costs in PJM have ranged from $0.5 billion to $2.05 billion per year. The fact that PJM rules continue to fail to ensure the return of 100 percent of congestion costs to the load that pays them means that higher congestion increases costs to load.

LMP may, at times, be set by transmission constraint penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors were fully implemented in PJM pricing effective February 1, 2019.[167]

167 For more information, see the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission constraint penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, generally results in at least a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers often reduce the control percent on transmission limits applied in SCED by the setting the limit to an average of 95 percent of its actual limit.[168] Violation of these reduced control percent line ratings results in penalty factors setting prices in SCED.[169]

Holding aside the issues with operators reducing the control percent in SCED, the more important point is that the underlying line ratings have a significant impact on the cost of energy and capacity but have never been reviewed or standardized by ISOs/RTOs or by regulators. The line ratings issues will begin to be addressed beginning on July 12, 2025.[170]

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was $200.30 per MW-day. The clearing price for the EMAAC LDA was $165.73 per MW-day.[171]

Transmission line ratings for a given transmission facility vary by the duration of the power flow, by ambient temperatures, by wind speed and by other conditions. Transmission lines can operate with higher loads for shorter periods of time. This is significant when a contingency is expected to last for only a short period. The transmission line rating can mean the difference between substantial congestion costs and no congestion costs.

168 See "Transmission Constraint Control Logic and Penalty Factors," presented at May 10, 2018, meeting of the Markets Implementation Committee Special Session Transmission Constraint Penalty Factors at p14. <https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-03-transmission-constraint-penalty-factor-education.ashx>.
169 See the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.
170 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").
171 See the "Analysis of the 2021/2022 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

The transmission line rating can mean the difference between a transmission penalty factor and no penalty factor.

In PJM, transmission owners use a range of ratings by duration.[172] PJM requires transmission owners to provide thermal ratings under normal operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings. In PJM, transmission owners have substantial discretion in the approach to line ratings.[173]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented.

Line ratings determine the actual value of transmission in market operations. Yet the methods for defining line ratings remain opaque and vary significantly across transmission owners. Under defining line ratings results in over building transmission. Dynamic line ratings are essential to reflect the actual availability of transmission in real time as ambient conditions change. Ensuring that system operators have accurate information about line ratings, including a wide range of line ratings by duration of load, are essential to ensure that all market participants receive the maximum value from the investment in the transmission system.

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings and implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when relevant.[174] The line rating methods should be public and fully transparent.

The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.[175] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

172 See "PJM Manual 03: Transmission Operations," Rev. 68 (May 21, 2025) § 2.1.1, at p 30.
173 PJM presentation to the Planning Committee (PC) (May 3, 2018) "Transmission Owner Ratings Development and Reporting in PJM" ("There are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check.") at 24.
174 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee.
175 *See* the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.

The Commission adopted rules that enhance the ability of PJM and the MMU to understand and monitor line ratings on the PJM grid. Order No. 881, issued December 16, 2021, requires that: transmission providers implement ambient adjusted ratings on transmission lines; RTOs/ISOs implement the systems and procedures necessary for hourly ratings updates; transmission providers use uniquely determined emergency ratings; transmission owners share transmission line ratings and transmission line rating methods with RTOs/ISOs and market monitors; transmission providers maintain a database of transmission line ratings and transmission line rating methods on OASIS or other password-protected website.[176] [177]

On rehearing, the Commission provided clarification of market monitors' ability to take action based on information received about transmission line ratings: "We expect that market monitors may use the transmission line rating information available to them in furtherance of their existing responsibilities, which are set forth in the Commission's regulations and the relevant tariffs of each RTO/ISO."[178]

Order No. 881 enhances transparency of information on line ratings and how they are determined. Requiring ambient and hourly adjustments constitutes substantive improvement. Continued reform consistent with the MMU's recommendations is needed in order to ensure consistent and accurate transmission line ratings in PJM.

By letter order issued November 22, 2023, the Commission accepted PJM's filing in compliance with Order Nos. 881 and 881-A, to be implemented no later than July 12, 2025.[179]

Order No. 881 did not require the use of dynamic line ratings ("DLR") based on an insufficient record.[180] On June 27, 2024, the Commission issued an Advanced Notice of Proposed Rulemaking in Docket RM24-6 on the implementation of dynamic line ratings.[181]

176 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").
177 *See* 18 CFR § 35.28(c)(5)&(g)(13).
178 Order No. 881-A at P 91.
179 See Docket No. ER22-2359-000. PJM must notify the Commission of the effective date no later than November 12, 2024.
180 Order No. 881 at PP 25, 254.
181 See 187 FERC ¶ 61,201.

Dynamic Line Ratings (DLR) and Grid Enhancing Technology (GETs)

For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real time prices are based on actual current line ratings. The relevant real-time conditions include ambient air temperature, wind speeds, solar heating, transmission line tension, and transmission line sag. The widespread adoption of dynamic line ratings should be pursued. The adoption of dynamic line ratings does not require the exorbitant incentives proposed by some. Dynamic line rating technology (DLR) and other Grid Enhancing Technology (GET) should be subject to competition and the costs of implementation should be capped at the costs that would result from the current cost of service method applied to transmission owners. The proposal that providers of GET should receive a share of forecast benefits is not consistent with competition, would pay rates of return many multiples of market rates of return and suffers from the same intractable problem of defining speculative benefits for long periods.

As a first small step towards broader implementation of DLR by all transmission owners in PJM, PPL Electric Utilities, on its own initiative, implemented DLR for three 230 KV transmission lines in northeastern Pennsylvania on October 6, 2022, that have experienced congestion. (The two circuit Susquehanna-Harwood path and the Juniata-Cumberland line.) PPL provides streaming data from the DLR system to PJM operators.

PJM developed technical reference guides to aid in the understanding and consideration of grid enhancing technologies on the PJM system. The technical reference guides provide additional information on dynamic line ratings, advanced power flow controllers, topology control and optimization and advanced conductors.[182]

182 See PJM. About PJM "Grid Optimization Solutions," <https://www.pjm.com/about-pjm/advanced-technologies/grid-optimization-solutions>.

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[183] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[184] The specific timeline is shown in Table 12-85.[185]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the 2024/2025 planning period and the first four months of the 2025/2026 planning period, regardless of when they were initially submitted.[186] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through September 2025.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[187] Table 12-84 shows that 66.6 percent of requested outages were planned for less than or equal to five days and 13.6 percent of requested outages were planned for greater than 30 days in the first four months of the 2025/2026 planning period. Table 12-84 also shows that 75.2 percent of the requested outages were planned for less than or equal to five days and 9.1 percent of requested outages were planned for greater than 30 days in the 2024/2025 planning period.

Table 12-84 Transmission facility outage request summary by planned duration: June 2024 through September 2025

	2024/2025 (12 months)		2025/2026 (4 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	15,092	75.2%	7,943	66.6%
>5 & <=30	3,148	15.7%	2,357	19.8%
>30	1,838	9.2%	1,618	13.6%
Total	20,078	100.0%	11,918	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-85.[188]

The purpose of the rules defined in Table 12-85 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and PJM can accurately model market conditions.[189]

Table 12-85 Transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	Received Status
<=5	Before the first of the month one month prior to the starting month of the outage	On Time
	After or on the first of the month one month prior to the starting month of the outage	Late
> 5 & <=30	Before the first of the month six months prior to the starting month of the outage	On Time
	After or on the first of the month six months prior to the starting month of the outage	Late
>30	Before the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	Late

183 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM, "Manual 3: Transmission Operations," Rev. 68 (May 21, 2025).
184 See PJM, "Manual 3: Transmission Operations," Rev. 68 (May 21, 2025).
185 See PJM, "Manual 3: Transmission Operations," Rev. 68 (May 21, 2025).
186 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active.
187 *Id.* at 70.
188 See PJM, "Manual 3: Transmission Operations," Rev. 68 (May 21, 2025).
189 See "*Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures*," Docket No. EL01-122-000 (November 2, 2001).

Table 12-86 shows a summary of requests by received status. In the first four months of the 2025/2026 planning period, 31.0 percent of outage requests received were late. In the 2024/2025 planning period, 40.5 percent of outage requests received were late.

Table 12-86 Transmission facility outage requests by received status: June 2024 through September 2025

	2024/2025 (12 months)				2025/2026 (4 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,558	5,534	15,092	36.7%	5,686	2,257	7,943	28.4%
>5 & <=30	1,684	1,464	3,148	46.5%	1,672	685	2,357	29.1%
>30	706	1,132	1,838	61.6%	863	755	1,618	46.7%
Total	11,948	8,130	20,078	40.5%	8,221	3,697	11,918	31.0%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[190]

Outages with emergency status will be approved even if submitted late after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[191] Table 12-87 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first four months of the 2025/2026 planning period, 9.4 percent were for emergency outages. Of all outage requests scheduled to occur in the 2024/2025 planning period, 12.1 percent were for emergency outages.

190 See PJM, "Manual 3: Transmission Operations," Rev. 68 (May 21, 2025). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).

191 PJM, "Manual 3: Transmission Operations," Rev. 68 (May 21, 2025).

Table 12-87 Transmission facility outage requests by emergency: June 2024 through September 2025

	2024/2025 (12 months)				2025/2026 (4 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,709	13,383	15,092	11.3%	784	7,159	7,943	9.9%
>5 & <=30	400	2,748	3,148	12.7%	149	2,208	2,357	6.3%
>30	325	1,513	1,838	17.7%	190	1,428	1,618	11.7%
Total	2,434	17,644	20,078	12.1%	1,123	10,795	11,918	9.4%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[192]

After PJM determines that a late request may cause congestion, PJM informs the transmission owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-88 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first four months of the 2025/2026 planning period, 7.8 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.5 percent (33 out of 935) were denied by PJM in the first four months of the 2025/2026 planning period and 17.0 percent (159 out of 935) were cancelled (Table 12-90). Of all outage requests submitted to occur in the 2024/2025 planning period, 9.0 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 5.2 percent (94 out of 1,813) were denied by PJM in the 2024/2025 planning period and 20.6 percent (373 out of 1,813) were cancelled (Table 12-90).

192 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 19 (Jan. 23, 2025).

Table 12-88 Transmission facility outage requests by congestion: June 2024 through September 2025

	2024/2025 (12 months)				2025/2026 (4 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,242	13,850	15,092	8.2%	548	7,395	7,943	6.9%
>5 & <=30	388	2,760	3,148	12.3%	230	2,127	2,357	9.8%
>30	187	1,651	1,838	10.2%	157	1,461	1,618	9.7%
Total	1,817	18,261	20,078	9.0%	935	10,983	11,918	7.8%

Table 12-89 shows the outage requests summary by received status, congestion status and emergency status. In the first four months of the 2025/2026 planning period, 21.8 percent of requests were submitted late and were nonemergency while 1.2 percent of requests (139 out of 11,918) were late, nonemergency, and expected to cause congestion. In the 2024/2025 planning period, 28.5 percent of requests were submitted late and were nonemergency while 1.6 percent of requests (324 out of 20,078) were late, nonemergency, and expected to cause congestion.

Table 12-89 Transmission facility outage requests by received status, emergency and congestion: June 2024 through September 2025

		2024/2025 (12 months)				2025/2026 (4 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	121	2,286	2,407	12.0%	63	1,031	1,094	9.2%
	Non Emergency	324	5,399	5,723	28.5%	139	2,464	2,603	21.8%
On Time	Emergency	2	25	27	0.1%	0	29	29	0.2%
	Non Emergency	1,370	10,551	11,921	59.4%	733	7,459	8,192	68.7%
Total		1,817	18,261	20,078	100.0%	935	10,983	11,918	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[193] Table 12-90 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-90. Table 12-90 shows that of all the outage requests that were expected to cause congestion, 3.5 percent (33 out of 935) were denied by PJM in the first four months of the 2025/2026 planning period, 43.0 percent were complete and 17.0 percent (159 out of 935) were cancelled. Of all the outage requests that were expected to cause congestion, 5.2 percent (94 out of 1,817) were denied by PJM in the 2024/2025 planning period, 67.3 percent were complete and 20.5 percent (373 out of 1,817) were cancelled.

193 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).

Table 12-90 Transmission facility outage requests by processed status[194]: June 2024 through September 2025

		2024/2025 (12 months)						2025/2026 (4 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	12	101	6	1	121	83.5%	4	49	9	1	63	77.8%
	Non Emergency	63	221	9	28	324	68.2%	24	76	27	7	139	54.7%
On Time	Emergency	1	1	0	0	2	50.0%	0	0	0	0	0	0.0%
	Non Emergency	297	899	97	65	1,370	65.6%	131	277	286	25	733	37.8%
Total		373	1,222	112	94	1,817	67.3%	159	402	322	33	935	43.0%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[195] The On Time or Late status affects the way in which PJM addresses the potential to exceed transmission limits. Table 12-90 shows that in the first four months of the 2025/2026 planning period, 139 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion and the options for controlling that congestion is the basis for PJM's treatment of late outage requests.

The definition of this congestion analysis in the PJM manuals is about physical limits and not about economic congestion. PJM approves on time outages based solely on whether limits are exceeded and available controlling actions, without regard to the resulting level of economic congestion. The MMU recommends that PJM draft a definition of the congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests.[196]

194 The number of denied transmission outage requests is lower than calculated by PJM the MMU includes only the transmission outage requests with "Denied" as a final status, while PJM included both transmission outage requests with "Denied" as a final status and transmission outage requests with "Denied" as an intermediate status.

195 OA Schedule 1 § 1.9.2.

196 "PJM Manual 38: Operations Planning," Rev. 19 (Jan. 23, 2025). p 21. Manual 38 states: "The outages are analyzed for reliability and expected off-costs. Each outage is studied and any constraints (actual or facility/contingency pair) trending toward a limit or exceeding a limit is noted in eDART. The trending or exceeding of a limit in the study is referred to as potential "congestion". The limit may be any or a combination of thermal, voltage, or stability issues. If there is an expected constraint, PJM will mark the corresponding eDART ticket as "congestion expected". The "congestion expected" flag is used to indicate a potential issue that may occur in the Day-Ahead Market or in Real-time Operations. If there are non-cost controlling actions, changes to the generation pattern, or changes to system conditions, the noted congestion may not occur in the Day-Ahead Market or in Real-time Operations. For "On-time" outages, PJM ensures the constraint can be mitigated by applying both non-cost and off-cost operations. If there are no limit exceedances as a result, the outage will be approved. For "Late" outages, PJM will apply only non-cost operations."

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. It is not clear that PJM's analysis of expected congestion identified or highlighted the magnitude of the economic impact. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion. After high congestion costs of Greys Point - Harmony Village constraint and market participant manipulative behavior caused by the outage were identified by the end of January, on February 11, 2022 Dominion decided to temporarily terminate the outage in March in order to work on upgrading Greys Point, Harmony Village and White Stone path. The Greys Point - Harmony Village Line has not been binding since March 14, 2022. It indicates that if the market impact of the outage was identified during PJM outage analysis process and action was taken because of the analysis result, the high congestion costs and manipulative behavior could have been prevented.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-91 is a summary of all the outage requests planned for the 2024/2025 planning period and the first four months of the 2025/2026 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled.

In the first four months of the 2025/2026 planning period, 17.1 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 7.6 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2024/2025 planning period, 29.4 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.[197]

Table 12-91 Rescheduled and cancelled transmission outage requests: June 2024 through September 2025

	2024/2025 (12 months)					2025/2026 (4 months)				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	15,092	3,028	20.1%	2,129	14.1%	7,943	1,113	14.0%	766	9.6%
>5 & <=30	3,148	1,734	55.1%	250	7.9%	2,357	500	21.2%	88	3.7%
>30	1,838	1,133	61.6%	92	5.0%	1,618	423	26.1%	48	3.0%
Total	20,078	5,895	29.4%	2,471	12.3%	11,918	2,036	17.1%	902	7.6%

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as On Time or Late.

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[198] This rule allows a TO to reschedule within the same month with very little notice.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[199] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-85) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-92 shows equipment outages by the equipment instead of by outage request.

Table 12-92 shows that there were 8,332 transmission equipment planned outages in the first four months of the 2025/2026 planning period, of which 1,400 or 16.8 percent were longer than 30 days, and of which 205 or 2.5 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

197 The number of tickets in each category can change over time. For example, a ticket initially classified as canceled or denied may be resubmitted at a later date for a different date range. Once approved the resubmitted ticket overrides the original ticket dates and details.
198 PJM, "Manual 3: Transmission Operations," Rev. 68 (May 21, 2025).
199 *Id.*

Table 12-92 Transmission equipment outages: June 2024 through September 2025

		2024/2025 (12 months)		2025/2026 (4 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,583	12.3%	1,400	16.8%
	Yes	251	1.9%	205	2.5%
<= 30		11,045	85.8%	6,727	80.7%
Total		12,879	100.0%	8,332	100.0%

Table 12-93 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[200] The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests was appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first four months of the 2025/2026 planning period, with an effective duration greater than a month and shorter than two months, there were 32 outages with a combined duration longer than 30 days.[201]

Table 12-93 Transmission equipment outages by effective duration: June 2024 through September 2025

	2024/2025 (12 months)		2025/2026 (4 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	9	3.6%	6	2.9%
>31 & <=62	33	13.1%	32	15.6%
>62 & <=93	18	7.2%	28	13.7%
>93	191	76.1%	139	67.8%
Total	251	100.0%	205	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR Auctions. The purpose of the rules governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and PJM can accurately model market conditions.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[202]

In the first four months of the 2025/2026 planning period, 112 outage requests were included in the annual FTR market outage list and 11,806 outage requests were not included.[203] In the 2024/2025 planning period, 436 outage requests were included in the annual FTR market outage list and 19,642 outage requests were not included. Table 12-94, Table 12-95, Table 12-96 and Table 12-97 show the summary information on the modeled outage requests and Table 12-98 and Table 12-99 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-94 shows that 23.2 percent of the outage requests modeled in the Annual FTR Market for the first four months of the 2025/2026 planning

200 A transmission facility is modeled as equipment in the EMS model. Equipment has three identifiers: location (B1), voltage level (B2) and equipment name (B3). The types of equipment include, for example, lines, transformers, and capacitors. There can be multiple outage requests associated with the same equipment.

201 The length of a planned equipment outage can be modified by editing an existing ticket for the equipment outage or by adding new equipment outage tickets for the same equipment.

202 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

203 PJM's treatment of transmission outages in the FTR models is discussed in the *2024 Quarterly State of the Market Report for PJM: January through June*, Section 13: FTRs and ARRs, Supply and Demand.

period had a planned duration of less than two weeks and that 25.9 percent of the outage requests (29 out of 112) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 23.2 percent of the outage requests modeled in the Annual FTR Market for the 2024/2025 planning period had a planned duration of less than two weeks and that 17.9 percent of the outage requests (78 out of 436) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-94 Annual FTR market modeled transmission facility outage requests by received status: June 2024 through September 2025

	2024/2025 (12 months)				2025/2026 (4 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	93	8	101	23.2%	22	5	27	13.2%
>=2 weeks & <2 months	142	20	162	37.2%	52	2	54	26.5%
>=2 months	123	50	173	39.7%	97	26	123	60.3%
Total	358	78	436	100.0%	171	33	204	100.0%

Table 12-95 shows the annual FTR market modeled outage requests summary by emergency status and received status. Two of the annual FTR market modeled outages expected to occur in the first four months of the 2025/2026 planning period were emergency outages. Three of the modeled outages expected to occur in the 2024/2025 planning period were emergency outages.

Table 12-95 Annual FTR market modeled transmission facility outage requests by emergency: June 2024 through September 2025

		2024/2025 (12 months)				2025/2026 (4 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	93	93	100.0%	0	22	22	100.0%
	>=2 weeks & <2 months	1	141	142	99.3%	0	52	52	100.0%
	>=2 months	0	123	123	100.0%	0	97	97	100.0%
	Total	1	357	358	99.7%	0	171	171	100.0%
Late	<2 weeks	0	8	8	100.0%	0	5	5	100.0%
	>=2 weeks & <2 months	0	20	20	100.0%	0	2	2	100.0%
	>=2 months	3	47	50	94.0%	2	24	26	92.3%
	Total	3	75	78	96.2%	2	31	33	93.9%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-96 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first four months of the 2025/2026 planning period and submitted late, 20.7 percent (6 out of 29) were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2024/2025 planning period and submitted late, 19.2 percent (15 out of 78) were expected to cause congestion.

Table 12-96 Annual FTR market modeled transmission facility outage requests by congestion: June 2024 through September 2025

		2024/2025 (12 months)				2025/2026 (4 months)			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	23	70	93	24.7%	7	15	22	31.8%
	>=2 weeks & <2 months	33	109	142	23.2%	22	30	52	42.3%
	>=2 months	32	91	123	26.0%	21	76	97	21.6%
	Total	88	270	358	24.6%	50	121	171	29.2%
Late	<2 weeks	2	6	8	25.0%	1	4	5	20.0%
	>=2 weeks & <2 months	4	16	20	20.0%	2	0	2	100.0%
	>=2 months	9	41	50	18.0%	2	24	26	7.7%
	Total	15	63	78	19.2%	5	28	33	15.2%

Table 12-97 shows that 27.3 percent of outage requests modeled in the annual FTR market for the first four months of the 2025/2026 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 24.1 percent for the 2024/2025 planning period. Table 12-97 also shows that 16.7 percent of outages requests modeled in the Annual FTR Market for the first four months of the 2025/2026 planning period and with a duration of two months or longer were cancelled, compared to 19.1 percent for the 2024/2025 planning period.

Table 12-97 Annual FTR market modeled transmission facility outage requests by processed status: June 2024 through September 2025

		2024/2025 (12 months)		2025/2026 (4 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	8	7.9%	9	33.3%
	Denied	1	1.0%	0	0.0%
	Approved	0	0.0%	1	3.7%
	Cancelled	28	27.7%	7	25.9%
	Revised	1	1.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	63	62.4%	10	37.0%
	Total	101	100.0%	27	100.0%
>=2 weeks & <2 months	In Progress	25	15.4%	37	68.5%
	Denied	0	0.0%	0	0.0%
	Approved	2	1.2%	0	0.0%
	Cancelled	39	24.1%	5	9.3%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	7	13.0%
	Completed	96	59.3%	5	9.3%
	Total	162	100.0%	54	100.0%
>=2 months	In Progress	24	13.9%	55	44.7%
	Denied	1	0.6%	1	0.8%
	Approved	1	0.6%	3	2.4%
	Cancelled	33	19.1%	12	9.8%
	Revised	0	0.0%	0	0.0%
	Active	14	8.1%	43	35.0%
	Completed	100	57.8%	9	7.3%
	Total	173	100.0%	123	100.0%
Total Cancelled		100	22.9%	24	11.8%
Grand Total		436		204	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first four months of the 2025/2026 planning period, 112 outage requests were modeled and 11,806 outage requests were not modeled in the Annual FTR Market. In the 2024/2025 planning period, 436 outage requests were modeled and 19,640 outage requests were not modeled in the Annual FTR Market.

Table 12-98 shows that 10.0 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date in the 2024/2025 planning period, compared to 20.3 percent in the 2024/2025 planning period.

Table 12-98 Transmission facility outage requests not modeled in Annual FTR Auction: June 2024 through September 2025

	2024/2025 (12 months)						2025/2026 (4 months)					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,819	8,468	82.3%	202	6,162	96.8%	2,153	4,324	66.8%	169	2,654	94.0%
>=2 weeks & <2 months	670	392	36.9%	164	861	84.0%	1,042	320	23.5%	148	405	73.2%
>=2 months	192	49	20.3%	252	411	62.0%	333	37	10.0%	322	185	36.5%
Total	2,681	8,909	76.9%	618	7,434	92.3%	3,528	4,681	57.0%	639	3,244	83.5%

Table 12-99 shows that 77.3 percent of late outage requests that were submitted after the Annual FTR Auction bidding opening date, were not modeled in the Annual FTR Auction, and had a duration longer than or equal to two months, were completed in the first four months of the 2025/2026 planning period. It also shows that 90.8 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were active or completed in the 2024/2025 planning period.

Table 12-99 Late transmission facility outage requests: June 2024 through September 2025

	2024/2025 (12 months)			2025/2026 (4 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,210	6,162	**84.6%**	2,021	2,654	76.1%
>=2 weeks & <2 months	725	861	**84.2%**	253	405	62.5%
>=2 months	373	411	**90.8%**	143	185	77.3%
Total	6,308	7,434	**84.9%**	2,417	3,244	74.5%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent those transmission outages from being submitted late. The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction opening date, based on those options.

Monthly FTR Market

When determining transmission outages to be modeled in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations less than or equal to five days. PJM exercises significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[204] Table 12-100 and Table 12-101 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-102 and Table 12-103 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-100 shows that on average, 31.4 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the first four months of the 2025/2026 planning period. On average, 28.8 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2024/2025 planning period.

Table 12-100 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2024 through September 2025

	2024/2025				2025/2026			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	272	134	406	33.0%	296	126	422	29.9%
Jul	154	100	254	39.4%	183	116	299	38.8%
Aug	211	101	312	32.4%	201	107	308	34.7%
Sep	488	175	663	26.4%	527	151	678	22.3%
Oct	542	190	732	26.0%				
Nov	511	197	708	27.8%				
Dec	359	127	486	26.1%				
Jan	239	80	319	25.1%				
Feb	275	103	378	27.2%				
Mar	477	158	635	24.9%				
Apr	515	192	707	27.2%				
May	482	203	685	29.6%				
Average	377	147	524	28.8%	302	125	427	31.4%

Table 12-101 shows that on average, 17.6 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first four months of the 2025/2026 planning period. On average, 20.1 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2024/2025 planning period.

204 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

Table 12-101 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2024 through September 2025

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2024/2025	Jun	28	13	16	93	0	90	166	406	22.9%
	Jul	22	8	15	41	0	97	71	254	16.1%
	Aug	18	16	10	68	0	81	119	312	21.8%
	Sep	70	7	30	111	0	192	253	663	16.7%
	Oct	60	1	19	174	2	209	267	732	23.8%
	Nov	63	5	23	124	0	185	308	708	17.5%
	Dec	40	16	8	101	0	101	220	486	20.8%
	Jan	41	9	9	67	0	110	83	319	21.0%
	Feb	27	6	11	79	0	116	139	378	20.9%
	Mar	62	5	19	139	1	164	245	635	21.9%
	Apr	61	6	18	133	0	200	289	707	18.8%
	May	43	11	17	135	1	123	355	685	19.7%
	Average	45	9	16	105	0	139	210	524	20.1%
2025/2026	Jun	50	20	15	72	0	91	174	422	17.1%
	Jul	29	17	10	52	0	97	94	299	17.4%
	Aug	39	9	8	49	0	84	119	308	15.9%
	Sep	73	6	25	128	1	204	241	678	18.9%
	Average	48	13	15	75	0	119	157	427	17.6%

Table 12-102 shows that on average, 15.4 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first four months of the 2025/2026 planning period, compared to 13.9 percent in the 2024/2025 planning period. On average, 62.9 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first four months of the 2025/2026 planning period, compared to 57.2 percent in the 2024/2025 planning period.

Table 12-102 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2024 through September 2025

	2024/2025						2025/2026					
	On Time			Late			On Time			Late		
	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
Jun	684	151	18.1%	376	566	60.1%	701	142	16.8%	428	728	63.0%
Jul	438	152	25.8%	304	541	64.0%	460	131	22.2%	344	652	65.5%
Aug	453	107	19.1%	296	482	62.0%	449	96	17.6%	352	628	64.1%
Sep	982	106	9.7%	335	530	61.3%	1,077	58	5.1%	412	590	58.9%
Oct	1,115	129	10.4%	412	733	64.0%						
Nov	717	81	10.2%	444	529	54.4%						
Dec	597	122	17.0%	428	487	53.2%						
Jan	1,109	135	10.9%	1,284	544	29.8%						
Feb	627	100	13.8%	411	529	56.3%						
Mar	1,221	140	10.3%	434	784	64.4%						
Apr	1,310	143	9.8%	506	694	57.8%						
May	1,121	148	11.7%	512	737	59.0%						
Average	865	126	13.9%	479	596	57.2%	672	107	15.4%	384	650	62.9%

Table 12-103 shows that on average, 68.7 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and completed in the first four months of the 2025/2026 planning period, compared to 67.0 percent in the 2024/2025 planning period.

Table 12-103 Late transmission facility outage requests: June 2024 through September 2025

	2024/2025			2025/2026		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	361	566	63.8%	494	728	67.9%
Jul	380	541	70.2%	421	652	64.6%
Aug	359	482	74.5%	482	628	76.8%
Sep	360	530	67.9%	386	590	65.4%
Oct	472	733	64.4%			
Nov	367	529	69.4%			
Dec	324	487	66.5%			
Jan	348	544	64.0%			
Feb	341	529	64.5%			
Mar	496	784	63.3%			
Apr	438	694	63.1%			
May	537	737	72.9%			
Average	399	596	67.0%	446	650	68.7%

Table 12-103 shows that only 0.9 percent of all outage requests were modeled in the Annual FTR Auction in the first four months of the 2025/2026 planning period, and 2.2 percent were modeled in the 2024/2025 planning period. For Monthly FTR Auctions in the first four months of the 2025/2026 planning period, an average of 12.3 percent of all outage requests were modeled, and 25.7 percent were modeled in the 2024/2025 planning period.

Table 12-104 FTR market modeled transmission facility outage requests: June 2024 through September 2025

	2024/2025 (12 months)			2025/2026 (4 months)		
Planned Duration	Annual Modeled	Monthly Modeled	Total	Annual Modeled	Monthly Modeled	Total
<2 weeks	101	3,220	3,321	27	905	932
>=2 weeks & <2 months	162	1,305	1,467	54	319	373
>=2 months	173	644	817	123	246	369
Total	436	5,169	5,605	204	1,470	1,674
All outage requests			20,078			12,296
Percent of Modeled	2.2%	25.7%	27.9%	1.7%	12.0%	13.6%

Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the day-ahead energy market so that market participants can understand market conditions and PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am.[205]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is available to market participants in eDART. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential impact on markets. If the three sets of outages differ, there is a potential negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

205 PJM, "Manual 3: Transmission Operations," Rev. 68 (May 21, 2025).

For example for the operating day of June 30, 2025, Figure 12-7 shows that: there were 278 approved or active outages seen by market participants before the day-ahead market was closed; there were 363 outage requests included in the day-ahead market model; there were 344 outage requests included in both sets of outages; there were 85 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 65 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

Figure 12-7 Illustration of day-ahead market analysis: June 30, 2025

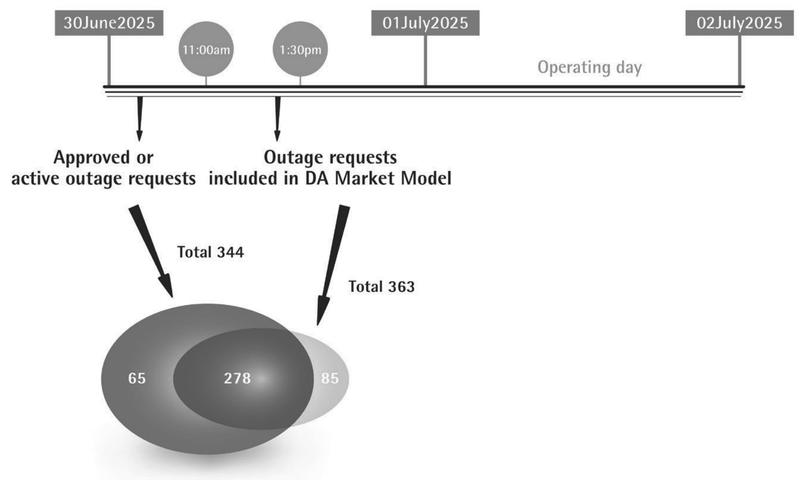


Figure 12-8 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.[206] Figure 12-8 shows that the number of outages modeled in the day-ahead market during the spring and fall has increased since 2021 (blue line), but many of these outages were not visible to market participants (gray line).

206 The analysis and figures in this report (Figure 12-8, Figure 12-9, and Figure 12-10) are based on a revised method (relative to the method used in prior State of the Market Reports) that correctly accounts for outages that did not, at the time the outage was active, have an end date specified on the outage ticket.

Figure 12-8 Approved or active outage requests: January 2015 through September 2025

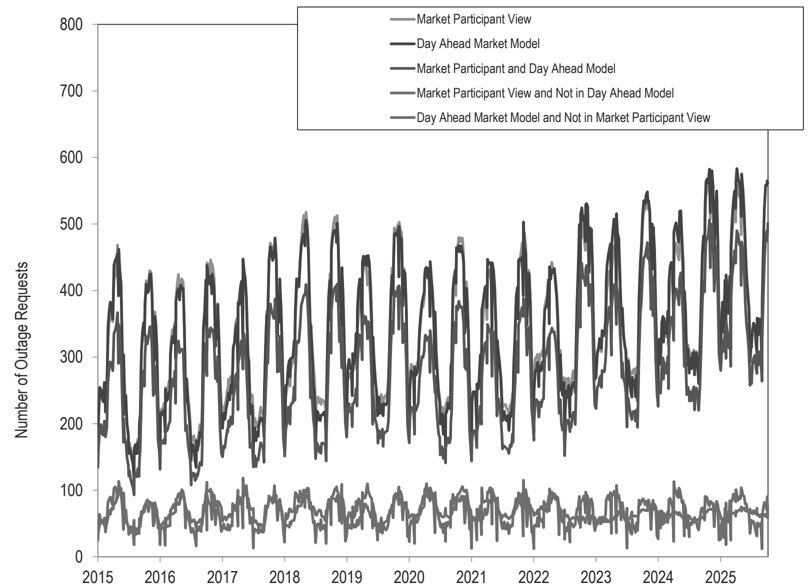


Figure 12-9 compares the weekly average number of outages included in the day-ahead market with the outages that actually occurred during the operating day. Figure 12-9 shows that beginning in 2021, the weekly average number of outages included in the day-ahead market (dark blue line) was higher in the spring and fall than previous years, but many of these outages did not actually occur in the real-time market (gray line). For example, some outages were scheduled to occur in day-ahead based on the information provided in eDART, but were cancelled or rescheduled in real time due to weather, equipment availability, reliability concerns, or the discretion of the transmission owner.

Figure 12-9 Day-ahead market model outages: January 2015 through September 2025

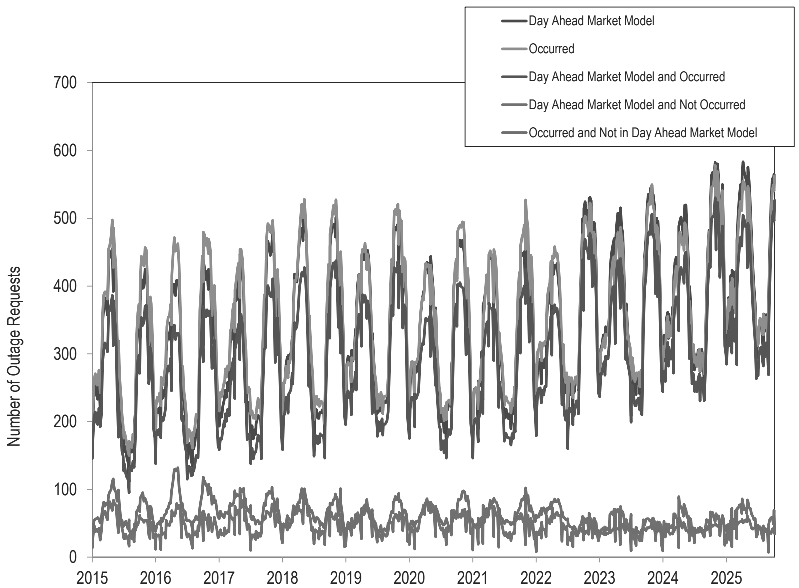


Figure 12-10 Approved or active outage requests: January 2015 through September 2025

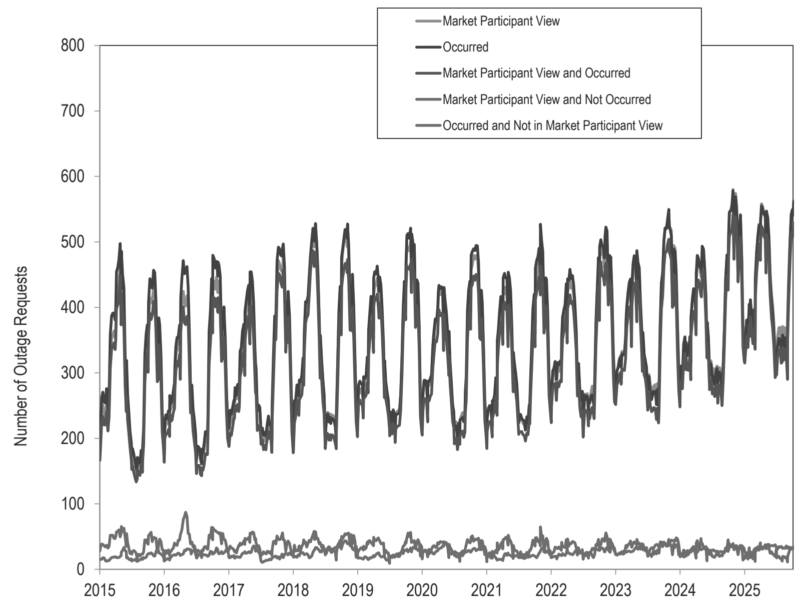


Figure 12-10 compares the weekly average number of active or approved outages for which information was visible to market participants through eDART prior to the close of the day-ahead market with the outages that actually occurred in the real time market during the operating day. Figure 12-10 shows the number of outages visible to market participants in eDART, but not actually occurring in the real time market, varies from less than 10 to over 100 in any given week.

Figure 12-8, Figure 12-9, and Figure 12-10 show that on a weekly average basis, for the full years 2023, 2024, and the first nine months of 2025, the active or approved outages for which information was visible to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, but when there are transmission constraints, load pays the high local price for all generation, including the low cost generation serving part of that load. The low cost generation receives payment only for its low local price and does not receive the payment made by load for the output of the low cost generation at the high local price. The result is that load pays the correct local price but pays too much in total for energy because it is paying more for the low cost generation than the low cost generation receives. Load pays the difference between the high local price and the low local price of the low cost generation. That payment is appropriately not made to the low cost generation which is paid its LMP. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the current FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective. The FTR mechanism has become unduly complicated and has deviated significantly from its original purpose. Return of all the excess payments to load would result in a perfect hedge against congestion. The current FTR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has added increasingly complex rules and regularly intervenes in the FTR mechanism as the PJM FTR design has moved further and further from these economic fundamentals. Some market participants have profited in various ways from these design flaws and those market participants now strongly defend the current design in the PJM stakeholder process and at FERC. The customers who ultimately pay congestion are generally not aware of the current, flawed FTR design and do not understand the extent to which the current design fails to offset their congestion payments compared to a fundamentally correct FTR design that would return congestion to load.

When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load, subject to transmission limits. This was true prior to the introduction of LMP markets and continues to be true in LMP markets.

After the introduction of LMP markets in PJM, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the combined day-ahead and real-time (balancing) markets. FTRs permitted the loads, which pay for the transmission system, to continue to receive the economic benefits of access to either local or remote low cost generation by returning congestion to the load.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning of the PJM FTR design that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. Prior to the introduction of LMP markets, payment for the delivery of low cost generation to load was based both on intrazonal generation and intrazonal transmission, both under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. Most load was served by intrazonal generation. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. There was no congestion revenue because customers paid only the actual cost of the low cost generation. The flawed idea that congestion is based on contract paths was inconsistent with the most basic logic of LMP and the resultant fissure has continued to widen. FTRs were a core part of the LMP design. FTRs ensured that the introduction of locational marginal pricing would not result in overpayments by load. The origin of FTRs was the recognition that the way to hold load harmless from making the excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load. The result of the current FTR mechanism is a significant reduction in the value of FTRs as a hedge for load. The current FTR mechanism results in significant wealth transfers from the load that pays congestion to traders of FTRs and traders of virtuals. The current FTR mechanism results in uneven and arbitrary differences in the share of congestion returned to load, depending on location and PJM's assignment of ARRs.

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP, but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants a hedge, it may enter into an arm's length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the purpose of FTRs.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs are a core theoretical part of the LMP design and were included in the PJM market design to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues should be assigned to the load that paid them through FTRs.[2] The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion payments must be defined correctly based on the way that power actually flows in the PJM network and not based on arbitrary contract paths.

Effective April 1, 1999, when FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and real-time (balancing) congestion to load.[3] Congestion is the sum of day-ahead and balancing congestion. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR design, the load still owns the rights to congestion revenue, but the ARR design allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR design, the right to all congestion revenues should belong to load and load should have the ability to retain or sell the congestion revenue rights on terms that load defines and accepts. The actual ARR implementation produces a very different result and fails to assign all congestion revenue rights to load.

ARRs were an add on concept, defined based on a misunderstanding of FTRs, which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. Contract paths are a fiction in a network. ARRs used assumed contract paths to assign congestion to load. The use of contract paths for ARRs was a more critical mistake than using contract paths for FTRs because contract paths did not, do not, and cannot account for all congestion. The use of contract paths led to the mistaken conclusion that there was some excess congestion that did not belong to load and could be sold to FTR buyers. The

2 See *id.* at 62, 259–62,260 & n. 123.
3 PJM refers to the combination of the day-ahead and real-time (balancing) markets as a two settlement system.

ARR concept, as it is currently implemented, does not allow the FTR sellers, load, to establish a price at which they are willing to sell, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. Sellers are required to return some of the cleared auction revenue to FTR buyers when FTR payments are less than target allocations. So called surplus revenue is paid to FTR holders to ensure payment, despite the fact that willing FTR buyers paid the revenues in the auction for the rights to an uncertain level of congestion.

The use of generation to load contract paths, rather than the direct calculation of congestion, led to an increased divergence between FTR target allocations on the generation to load contract paths and actual total congestion. This divergence between actual network use and historic contract paths was exacerbated as new zones were added with their own historic generation to load contract paths and as significant numbers of generating units retired and new units were added.[4] Rather than understanding that the divergence resulted from the fact that a contract path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined contract paths was returned to load, regardless of its source. There is no such thing as excess congestion. Congestion is congestion. In a well designed LMP/FTR system, all congestion is returned to load, neither more nor less. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on the contract path fiction undermined the assignment of all congestion rights to load.

4 For a comprehensive report on capacity retirements and capacity additions in PJM, see: "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022," (September 15, 2020) available at <http://www.monitoringanalytics.com/reports/Reports/2020/Constraint_Based_Congestion_Calculations_20200722.pdf>.

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs. If FTRs only returned congestion to FTR holders, there could be no such thing as revenue inadequacy. As currently defined in PJM, FTR revenue adequacy simply compares day-ahead congestion revenues to FTR target allocations. (Target allocations are the day-ahead CLMP differences, shadow prices, between the source and sink of the FTR times the MW of the FTR.) There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. There are systematic differences between FTR target allocations and actual congestion in aggregate and on a path by path basis. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment. Yet PJM treats target allocations as a guarantee of payment and takes what is termed surplus auction revenue from ARR holders (load) and gives it to FTR holders when day-ahead congestion revenues are not enough to cover all FTR target allocations.

The contract path fiction is also the source of the incorrect definition of the product that is bought and sold as FTRs, the available supply of the product and the price paid to the buyers of the product. The FTR product is defined as the difference in congestion prices in the day-ahead market only, across specific transmission contract paths (the shadow price), multiplied by the FTR MW position on those paths. That is the definition of FTR target allocation. The difference in congestion prices across contract paths is not congestion and is not equal to congestion revenues when multiplied by the FTR MW position. The MW quantity of the product made available for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not actual market flows and system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. Congestion is defined as the difference in congestion prices across a path multiplied by the market flow on that path, recognizing both day-ahead and balancing market results. That is the measure of the amount load pays in excess of what generation receives. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. This fundamental confusion in the design of the market is the source of so called revenue shortfalls, of the redesign of the market to exclude balancing congestion, and of the need for PJM to intervene in the market. PJM has had to regularly intervene in the market because the market as designed cannot reach equilibrium based on the economic fundamentals. The product, the quantity of the product, and the price of the product are all incorrectly defined.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead price differences only, the fact that ARR holders cannot set the sale price for the congestion revenue rights they own, the return of market revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach retained the contract path based view of how load is served that is fundamentally inconsistent with the way load is actually served in a network system and therefore inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first four months of the 2025/2026 planning period, using the rules effective for each planning period, was only 68.7 percent. Only 68.7 percent of congestion revenue was returned to load over this period. Load was underpaid by $5.4 billion from the 2011/2012 planning period through the first four months of the 2025/2026 planning period. This is an increase of $0.5 billion in underpayment to load from the end of the 2024/2025 planning period through the first four months of the 2025/2026 planning period.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design had not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. The design should simply have provided for the return of all congestion revenues to load. The design should have also provided for the ability of load to sell the rights to congestion revenue. That sale could be organized as an FTR auction with the product and the price clearly defined. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

The *2025 Quarterly State of the Market Report for PJM: January through September* focuses on the 2024/2025 planning period as well as the 2025/2026 Long Term and Annual FTR auctions and ARR allocation, specifically covering June 1, 2024, through September 30, 2025. The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were partially competitive in the first nine months of 2025.

Table 13-1 The FTR/ARR markets results were partially competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Partially Competitive	
Market Performance	**Partially Competitive**	**Flawed**

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2025/2028 Long Term FTR Auction, the 2025/2026 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions for prevailing flow FTRs. The ownership of FTR obligations is unconcentrated or moderately concentrated for each period of the Monthly Balance of Planning Period Auctions for counter flow FTRs. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and unconcentrated for the 2025/2026 Annual FTR Auction. Ownership of current FTRs is disproportionately (88.7 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs have no option to set an acceptable sale price and are not permitted to participate in the market clearing in any way and are not assured they will receive 100 percent of auction revenues.
- Market performance was evaluated as partially competitive because of the significant and persistent flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant, fundamental and persistent flaws in the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears and, as a result, sellers are not assured they will receive 100 percent of auction revenues. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. The ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- The fact that load is not able to define its willingness to sell FTRs or to set the prices at which it is willing to sell FTRs and the fact that load is required to return some of the cleared auction revenue to FTR buyers when FTR profits are deemed to be not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Overview

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2025/2026 planning period ARRs were allocated to 1,560 individual participants, held by 130 parent companies, up from 1,523 individual parents, held by 126 parent companies in the 2024/2025 planning period. ARR ownership for the 2025/2026 planning period was unconcentrated with an HHI of 600, down from 610 for the 2024/2025 planning period.

Market Behavior

- **Self Scheduled FTRs.** For the 2025/2026 planning period, 25.9 percent of eligible ARRs were self scheduled as FTRs, up from 25.3 percent for the 2024/2025 planning period.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first four months of the 2025/2026 planning period, ARRs and self scheduled FTRs offset only 66.6 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $5.4 billion from the 2011/2012 planning period through the first four months of the 2025/2026 planning period. The cumulative offset for that period was only 68.7 percent of total congestion. If ARR holders had self scheduled all of their allocated FTRs as ARRs for the first four months of the 2025/2026 planning period, the ARR target allocations would have increased the offset from 66.6 percent to 98.7 percent of total congestion.
- **ARR Payments.** For the first four months of the 2025/2026 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $1,859.0 million, while PJM collected $2,088.2 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2024/2025 planning period, the ARR target allocations were $1,448.1 million while PJM collected $1,664.9 million from the combined Annual and the first four Monthly Balance of Planning Period FTR Auctions.
- **ARR.** For the first four months of the 2025/2026 planning period there was enough total day-ahead congestion to pay FTR target allocations. However, as a result of the monthly settlement logic for FTRs and ARRs, $22.6 million of FTR auction revenue over ARR target allocations was transferred from ARR holders (load) to FTR holders. In the 2024/2025 all $196.2 million of FTR auction revenue over ARR target allocations was transferred from ARR holders to FTR holders. Although PJM refers to this as a surplus, there is no such thing as surplus FTR auction revenue based on market logic. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason.
- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first four months of the 2025/2026 planning period, as a result of transmission capability being returned to service from outages included in the annual model, PJM allocated a total of 16,614.7 MW of residual ARRs, up 8,616.5 MW (a 107.7 percent increase) from 7,998.2 MW, with a total target allocation of $50.5 million, up $45.0 million (an 819.9 percent increase) from $5.5 million in the same period of the 2024/2025 planning period.
- **ARR Deficiency.** In July 2025 there was not enough FTR auction revenue collected from the monthly FTR auction to pay the high target allocations from Residual ARRs. As a result, July ARR funding was deficient for the first time since ARRs were introduced. Deficient ARRs will be funded at the end of the planning period from surplus FTR revenues, if there is an

FTR surplus, or through an uplift charge to FTR holders if there is not an FTR surplus.

- **ARR Reassignment for Retail Load Switching.** There were 16,509 MW of ARRs associated with $385.7 thousand of revenue that were reassigned for the first four months of the 2025/2026 planning period. There were 11,996 MW of ARRs associated with $184.3 thousand of revenue that were reassigned in the same period of the 2024/2025 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions includes auctions for each remaining month in the planning period.

Market Structure

- **Patterns of Ownership.**[5] For the Monthly Balance of Planning Period Auctions, financial entities purchased 96.4 of all prevailing and counter flow FTRs, including 95.3 percent of prevailing flow and 97.7 percent of counter flow FTRs for the first four months of the 2025/2026 planning period. Financial entities owned 88.7 percent of all prevailing and counter flow FTRs, including 82.5 percent of all prevailing flow FTRs and 95.7 percent of all counter flow FTRs during the first four months of the 2025/2026 planning period. Self scheduled FTRs account for 4.3 percent of all FTR held.
- **Market Concentration.** In the Monthly Balance of Planning Period Auctions for the first four months of the 2025/2026 planning period, ownership of cleared prevailing flow bids was unconcentrated in all periods. Ownership of cleared counter flow bids was unconcentrated in 47.6 percent of periods and moderately concentrated in 52.4 percent of periods.

5 Beginning in the *2025 Quarterly State of the Market Report for PJM: January through March*, the MMU categorizes all participants owning FTRs in PJM as either physical or financial at an account level. In prior reports, participants were categorized as either physical or financial at an organization level.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the 2025/2028 Long Term FTR Auction, total participant FTR sell offers were 1,557,455 MW. In the 2025/2026 Annual FTR Auction, total participant FTR sell offers were 1,695,004 MW. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2025/2026 planning period, total participant FTR sell offers were 31,730,557 MW.
- **Buy Bids.** In the 2025/2028 Long Term FTR auction, total FTR buy bids were 6,729,000 MW, up 72.0 percent from 5,729,618 MW the previous long term auction. There were 6,658,483 MW of buy and self scheduled bids in the 2025/2026 Annual FTR Auction, up 39.6 percent from 4,770.381 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2025/2026 planning period were 48,912,396 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $1,312.2 thousand for the first four months of the 2025/2026 planning period, up 38.0 percent from $951.0 thousand from the same period of the2024/2025 planning period.
- **Credit.** There were no collateral defaults and two payment defaults in the first nine months of 2025.

Market Performance

- **Quantity.** In the 2025/2028 Long Term FTR Auction 923,869 MW (13.7 percent) of buy bids cleared and 168,852 MW (10.8 percent) of sell offers cleared. In the 2025/2026 Annual FTR Auction 1,324,299 MW (19.9 percent) of buy and self scheduled bids cleared, up 28.8 percent from the 2024/2025 Annual FTR Auction, and 183,410 MW (10.8 percent) of sell offers cleared, up 47.6 percent from the 2024/2025 Annual Auction. In the first four months of the 2025/2026 planning period, Monthly Balance of Planning Period FTR Auctions 8,010,114 MW (16.4 percent) of FTR buy bids cleared, up 54.9 percent from the the same period of the 2024/2025 planning period and 5,089,192 MW (16.0 percent) of FTR sell offers cleared, up 36.5 percent from the same period of the 2024/2025 planning period.

- **Price.** The weighted average buy bid FTR price in the 2025/2028 Long Term FTR Auction was $0.09 per MW, up from $0.07 from the 2024/2027 Long Term FTR Auction. The weighted average buy bid FTR price in the Annual FTR Auction for the 2025/2026 planning period was $0.50 per MW, up from $0.30 per MW in the 2024/2025 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods in the first four months of the 2025/2026 planning period was $0.36 per MWh, down from $0.42 in the 2024/2025 planning period.
- **Revenue.** The 2025/2028 Long Term FTR Auction generated $162.3 million of net revenue for all FTRs, up 58.2 percent from $102.6 million from the 2024/2027 Long Term FTR Auction. The 2025/2026 Annual FTR Auction generated $1,895.3 million in net revenue, up 28.5 percent from $1,475.3 million for the 2024/2025 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $39.9 million in the first four months of the 2025/2026 planning period, down 20.4 percent from $50.1 million in the same period of the 2024/2025 planning period.
- **"Revenue Adequacy."** For the first four months of the 2025/2026 planning period there was enough total day-ahead congestion revenue to pay FTR target allocations. However, as a result of the monthly settlement logic for FTRs and ARRs, $22.6 million of FTR auction revenue was transferred from ARR holders (load) to FTR holders, and FTRs were paid 100.0 percent of the target allocations for the first four months of the 2025/2026 planning period. Based on market logic, there is no such thing as surplus FTR auction revenue and there is no such thing as revenue inadequacy. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of buying the FTR. In the first four months of the 2025/2026 planning period, profits for all participants were $445.8 million, up from $351.8 million in profits in the same time period in the 2024/2025 planning period. In the first four months of the 2025/2026 planning period, physical entities received $93.0 million in profits on FTRs purchased directly (not self scheduled), up from $36.4 million profits in the same time period in the 2024/2025 planning period. Financial entities received $352.8 million in profits, up from $315.4 million profits in the same time period in the 2024/2025 planning period.

Markets Timeline

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Table 13-2 shows the date of first availability and final closing date for all ARR and FTR auctions with bidding days that occur in 2025.

Table 13-2 Annual FTR auction dates

Auction	Initial Open Date	Final Close Date
2024/2025 Monthly	14-May-24	18-Apr-25
2025/2028 Long Term	3-Jun-24	3-Mar-25
2025/2026 ARR	5-Mar-25	22-Mar-24
2025/2026 Annual	9-Apr-25	2-May-25
2026/2029 Long Term	2-Jun-25	04-Mar-26
2025/2026 Monthly	15-May-25	17-Apr-26

Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion revenue that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions in allocated revenue as a contingency for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including both day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported 2022. Status: Not adopted.)[6]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

"Surplus"

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[7] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)

6 If adopted, this recommendation would replace the next two recommendations.

7 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost to the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends that PJM's minimum credit requirements be reviewed and updated to appropriately reflect the risk created for the markets and other market participants. The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollars amounts in 2011 in FERC order 741 based on the specific market participation (FTRs or other). (Priority: Medium. New recommendation. Status: Not adopted.)

Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in PJM's security constrained LMP market. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right should be to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the voluntary sale by load of their congestion revenue rights at terms defined by load, recognizing that load has property rights to congestion.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without the use of generation to load contract paths, and if the distortions subsequently introduced into the FTR design had not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives including so called revenue adequacy. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[8] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[9] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that actual congestion is the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

A subsequent rule change was implemented that modified the allocation of what is termed surplus auction revenue to load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[10] ARR holders will only be allocated this surplus after FTRs are paid 100 percent of their target allocations. While this rule change increased the level of congestion revenues returned to load under some conditions, the rules do not recognize ARR holders' rights to all congestion revenue, and only improves congestion payouts to load when there is a surplus. There was no surplus for the 2020/2021 or 2021/2022 planning years. With this rule in effect for the 2021/2022 planning period, ARRs and self scheduled FTRs offset 31.6 percent of total congestion. There was surplus for the 2022/2023 and the 2023/2024 planning periods. However, FTR auction surplus revenues were taken from load and given to FTR holders because day-ahead congestion revenues were less than target allocations in the 2023/2024 planning period. For the 2024/2025 planning period, there was not enough congestion revenue to fund FTR target allocations and all FTR auction surplus revenues were taken from load and given to FTR holders. Based on market logic, there is no such thing as surplus FTR auction revenue. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders, and should not be returned to FTR buyers for any reason. ARRs and self scheduled FTRs offset only 66.6 percent of total congestion paid by load in the first four months of the 2025/2026 planning period. Load

8 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
9 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 158 FERC ¶ 61,093 (2017).
10 163 FERC ¶ 61,165 (2018).

has been underpaid congestion revenues by $5.4 billion from the 2011/2012 planning period through the first four months of the 2025/2026 planning period. The cumulative offset for that period was only 68.7 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs is entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not actually built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

PJM proposed, and on March 11, 2022, FERC accepted, an increase to Stage 1A ARR allocations from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL).[11] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior twelve month period, and NSPL is a network service customer's contribution to the highest daily zonal peak load in the prior twelve month period. PJM's new ARR allocation rules have increased Stage 1A rights at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's new ARR allocation rules have exacerbated the current misalignment between congestion property rights and the congestion paid by load.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the voluntary sale by load of their congestion revenue rights at terms defined by load.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other rights holders. In the case of a defaulting buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy and what generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that is credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with the auction clearing price for the 50 percent of the CRR that was sold to the third party. Depending on actual congestion and

11 See 178 FERC ¶ 61,170.

the price paid for a CRR, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly and/or more frequent.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.

Auction Revenue Rights

Auction Revenue Rights (ARRs) are the mechanism used to assign congestion rights to load, using an archaic and invalid contract path based approach, and to sell those rights to FTR buyers in various auctions. ARR values are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction. ARR sellers have no opportunity to define a price at which they are willing to sell and must accept the prices set by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. But some auction revenues may be returned to FTR buyers as "surplus," despite the fact that FTR buyers willingly paid a defined price for FTRs. There is no surplus. PJM has significant discretion over the level of supply made available to FTR buyers. That discretion is needed only as a result of the flawed design. As long as the current design persists, the goals of that discretion should be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 24 hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between the ARR sink and source from the Annual FTR Auction.[12] The value of ARR target allocations is set by the Annual FTR Auction. ARRs would be revenue inadequate if the money collected from the Annual FTR auction is not enough to pay the entirety of Annual ARR target allocations for the planning period which could happen only if there is a modeling difference between the system model used for ARRs and the system model used for FTRs and the FTR MW are reduced. The Annual FTR Auction and ARR target allocations were not the issue in the first four months of the 2025/2026 planning period. The disproportionate increase in Residual ARR target allocations compared to Annual ARR target allocations and FTR Auction Revenue led to the first month with an ARR deficiency in the history of the ARR market. An ARR's target allocation, or value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all congestion revenues. In the current design, all auction revenues should be paid to ARR holders.

The quantity of the product made available as ARRs or for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference and system capability is not the market flow across transmission paths. The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of the concept of system capability in assigning ARRs is derived entirely from the contract path approach used in the PJM design. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability were available for sale as FTRs. Power does not flow on contract paths. In the current approach,

12 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints.

system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage 1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model despite the fact that there are not real world paths, real world capability, or real world flows that correspond to Stage 1A rights.

Market Design

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone. For the 2006/2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DUQ and DOM Control Zones. For the 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Each March, PJM allocates annual ARRs to eligible customers in a three stage process: Stage 1A, Stage 1B and Stage 2B. Stage 1A ARRs are assigned based on historic contract paths and Stage 1A ARRs must be preserved for at least ten planning periods regardless of system or regulatory changes.[13]

The 2022/2023 planning period annual auction was the first auction under PJM's new ARR allocation rules. Under the new rules, Stage 1A ARR allocations increase from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL).[14] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior 12 month period, and NSPL is a network service customer's contribution to the highest daily zonal peak load in the prior twelve month period. PJM's new ARR allocation rules have increased Stage 1A rights at the cost of Stage 1B and Stage 2 ARR allocations.

In Stage 1A, LSEs can obtain ARRs, based on their contribution to the network service peak load (NSPL) and based on putative generation to load contract paths, or their qualified replacements if the resource has retired and PJM has replaced it with a different generator regardless of whether there is a contract. The historical reference year is the year in which PJM markets were implemented, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the historical reference year, subject to a cap of 60 percent of the participants total network service peak load for the zone or load aggregation zone that the ARRs are obtained. Effective for the 2023/2024 planning period, network service customers can obtain Stage 1A ARRs based on the MW of firm service provided during the reference year, subject to a cap of 60 percent of the participants total network service peak load for the zone or load aggregation zone that the ARRs are obtained. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[15] However, PJM does not actually upgrade the transmission system to address Stage 1A ARR infeasibility because there is no actual physical infeasibility. The apparent infeasibility is an artificial result based on the fiction that power flows on the unsupported, outdated, fictional and irrelevant generation to load contract paths on which PJM's current and incorrect ARR allocation is based. Stage 1A rights have nothing to do with actual power flows or transmission limits.

In Stage 1B, network transmission service customers can obtain ARRs, up to the difference between their share of network service peak load and Stage 1A allocations. Effective for the 2023/2024 planning period, Stage 1B ARRs can be obtained from historical generation resources, qualified replacement resources, hubs, zones, or interfaces to designated load aggregation zones. Firm, point to point transmission service customers can obtain ARRs based

13 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025) at 20.
14 See 178 FERC ¶ 61,170.
15 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025)

on the MW of long-term, firm, point to point service provided between the receipt and delivery points for the historical reference year.

In Stage 2, network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone, load aggregation zone, or any generator, interface, hub or zone, up to their total peak network load in that zone. Firm, point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[16] When ARR holders self schedule FTRs, the ARR holders choose to be paid based on variable FTR target allocations rather than the fixed ARR value determined in the annual FTR auction. ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction.

Effective for the 2015/2016 planning period, when residual zonal pricing was introduced, ARRs default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[17]

In 2016, FERC ordered PJM to remove retired resources from the generation to load contract paths used to allocate Stage 1A ARRs.[18] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs), regardless of whether there was a corresponding contract.[19] Existing Stage 1A resources retain their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load contract paths should not be used as a basis for assigning the rights to congestion revenue. There is no basis for assuming that a contract existed in 1999 or exists currently. Contract paths are a fiction and are not an accurate representation of the reasons that congestion exists or of how load is served in a network and will, by definition, not accurately measure the exposure of load to congestion.

16 OATT Attachment K 7.1.1.(b).
17 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025) at 35.
18 156 FERC ¶ 61,180 (2016) *reh'g denied*, 158 FERC ¶ 61,093 (2017).
19 See FERC Docket No. EL16-6-003.

Market Structure

ARRs are allocated on an annual basis. For the 2025/2026 planning period there were 1,560 individual participants and 130 parent companies, up from 1,523 individual participants and 126 parent companies for the 2024/2025 planning period.

The ownership of ARRs by parent company was unconcentrated, with an HHI of 600, for the 2025/2026 planning period compared to 610 for the 2024/2025 planning period.

Market Performance

Volume

Table 13-3 shows the MW of ARR allocations for each round of the 2024/2025 and 2025/2026 planning periods. There was a 3,011 MW increase (1.9 percent) in Network Service Peak Load (NSPL) between the 2024/2025 and 2025/2026 planning period. This increase resulted in an increase in ARR MW requested by load in the annual auction of 1,858 MW (0.9 percent) from the 2024/2025 to the 2025/2026 planning period. The ARR MW actually provided to load decreased by 1,559 MW (1.4 percent) from the 2024/2025 to the 2025/2026 planning period. The cleared volume of Stage 1B ARR MW decreased 3.4 percentage points from 26.5 percent in the 2024/2025 planning period to 23.1 percent in the 2025/2026 planning period.

Table 13-3 Annual ARR allocation volume: 2024/2025 and 2025/2026 planning periods

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2024/2025	1A	0	33,729	86,657	86,657	100.0%	0	0.0%
	1B	1	11,182	56,080	14,880	26.5%	41,200	73.5%
	2	2	14,374	31,556	5,691	18.0%	25,865	82.0%
		3	9,552	31,520	7,788	24.7%	23,732	75.3%
		Total	23,926	63,076	13,479	21.4%	49,597	78.6%
	Total		68,837	205,813	115,016	55.9%	90,797	44.1%
2025/2026	1A	0	35,072	89,253	89,245	100.0%	8	0.0%
	1B	1	10,807	55,826	12,919	23.1%	42,907	76.9%
	2	2	9,006	31,316	5,261	16.8%	26,055	83.2%
		3	6,660	31,276	6,032	19.3%	25,244	80.7%
		Total	15,666	62,592	11,293	18.0%	51,299	82.0%
	Total		61,545	207,671	113,457	54.6%	94,214	45.4%

Table 13-4 shows the share of ARR MW, by stage, for ARRs with paths that source inside or outside the zone where the load is located, for the 2025/2026 planning period. Table 13-4 shows that, for the 2025/2026 planning period, 78.6 percent of the ARR MW are based on generation inside the zone where the ARR load is located and 21.4 percent of the ARR MW are based on generation outside the zone where the ARR load is located. In contrast, only 15.5 percent of congestion resulted from constraints inside the zone where load is located and 84.5 percent of congestion resulted from constraints outside the zone where load is located during the 2024/2025 planning period (Table 13-53). This illustrates one of the fundamental issues with the path based approach which originated in a cost of service design where most load was served by generation in the same zone as load. In fact, in the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load. The path based approach cannot and does not reflect the actual congestion paid by load.

Table 13-4 Share of ARRs that source in/out of load zone: 2025/2026 planning period

	Stage 1A		Stage 1B		Stage 2		Total	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	31.1%	36.3%	4.7%	9.3%	8.3%	10.3%	44.1%	55.9%
AEP	9.4%	55.8%	1.6%	20.6%	3.0%	9.6%	13.9%	86.1%
APS	9.4%	69.7%	0.9%	13.1%	1.2%	5.8%	11.5%	88.5%
ATSI	38.9%	47.8%	1.2%	2.9%	1.5%	7.7%	41.5%	58.5%
BGE	34.9%	48.5%	10.5%	0.0%	4.0%	2.1%	49.4%	50.6%
COMED	0.0%	64.2%	0.0%	8.7%	0.0%	27.2%	0.0%	100.0%
DAY	69.0%	8.7%	3.6%	7.3%	7.4%	4.1%	79.9%	20.1%
DOM	0.5%	94.1%	0.0%	0.9%	0.0%	4.5%	0.5%	99.5%
DPL	22.0%	64.5%	2.9%	1.3%	3.8%	5.5%	28.7%	71.3%
DUKE	48.4%	46.0%	0.8%	2.8%	0.6%	1.4%	49.8%	50.2%
DUQ	68.4%	4.1%	7.5%	0.4%	15.3%	4.3%	91.2%	8.8%
EKPC	48.7%	0.0%	38.4%	0.0%	12.5%	0.4%	99.6%	0.4%
EXT	22.7%	0.0%	0.0%	0.0%	77.3%	0.0%	100.0%	0.0%
JCPL	10.4%	26.8%	31.8%	0.5%	30.0%	0.5%	72.2%	27.8%
MEC	16.5%	53.1%	7.0%	0.5%	6.8%	16.2%	30.2%	69.8%
OVEC	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	0.0%
PE	25.7%	42.3%	0.2%	5.0%	0.6%	26.1%	26.5%	73.5%
PECO	1.8%	93.4%	0.2%	1.0%	0.3%	3.4%	2.3%	97.7%
PEPCO	24.1%	60.8%	0.0%	11.8%	0.0%	3.3%	24.1%	75.9%
PPL	0.0%	62.6%	0.4%	5.7%	0.6%	30.7%	1.0%	99.0%
PSEG	22.4%	36.4%	24.5%	0.1%	6.6%	10.0%	53.5%	46.5%
REC	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Total	14.8%	58.8%	3.9%	7.5%	2.7%	12.4%	21.4%	78.6%

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a year, but guaranteed for 10 years, with the ability for a participant to opt out of any planning period within the 10 years. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process. But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

For the 2024/2025 and 2025/2026 planning periods, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. Stage 1A related over allocations have to be made up elsewhere in PJM's FTR market model, in the form of reduced system capability, in order for PJM to achieve its goal of fully funding FTRs. The need for and use of these artificial and factually incorrect calculations are another illustration of the failure of the FTR/ARR design to meet basic logical standards.

Table 13-5 shows the MW quantity and count of overloaded constraint/contingency pairs and the reasons for the modeled overload for the 2024/2025 and 2025/2026 planning periods. In order to eliminate the infeasibilities for the requested Stage 1A ARR allocations, PJM needed to raise the modeled capacity limits above the actual transmission line limits on 113 constraint/contingency pairs, 84 of which were internal to PJM, a total of 25,565 MW in the 2025/2026 planning period. This is an increase of 15 constraint/contingency pairs (15.3 percent), an increase of 27 constraint/contingency pairs internal to PJM, (47.4 percent), and an increase of 8,691 MW (51.5 percent) compared to the 2024/2025 planning period.[20]

20 *PJM 2023/2024 Stage 1A Over allocation notice*, PJM FTRs, <https://pjm.com/-/media/markets-ops/ftr/annual-arr-allocation/2023-2024/2023-2024-stage-1a-over-allocation-notice.ashx> (March 6, 2023).

Table 13-5 Stage 1A overloaded constraint reasons and MW: 2024/2025 and 2025/2026 planning periods

		2024/2025		2025/2026	
Reason	Type	MW	Count	MW	Count
Network Load	Internal PJM	2,745	5	17	1
Network Load	M2M Flowgate	2,003	26	2,177	23
Transmission Outage	Internal PJM	12,031	57	23,316	84
Transmission Outage	M2M Flowgate	95	10	55	5
Transmission Outage	Tie Line	0	0	0	0
Total		16,874	98	25,565	113

Table 13-6 shows the share of Stage 1A over allocations for the 2024/2025 and 2025/2026 planning periods for ARR allocations that source inside and outside the zone where the over allocated MW sink. The share of over allocations that has a source outside the zone in which it sinks, increased 3.4 percent from 26.8 percent in the 2024/2025 planning period to 27.7 percent in the 2025/2026 planning period. The total MW of overloaded constraint/contingency pairs (Table 13-5) is greater than the total MW of overloaded Stage 1A ARR paths (Table 13-6) because an individual overloaded ARR path can require the modeled capacity limit to be increased for multiple constraint/contingency pairs and multiple contingencies per constraint.

Table 13-6 Stage 1A overloaded paths that sink inside and outside source zone: 2024/2025 and 2025/2026 planning periods

	2024/2025 Planning Period				2025/2026 Planning Period			
	MW		Proportion		MW		Proportion	
	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone
ACEC	0.0	0.1	0.0%	100.0%	0.0	0.0	NA	NA
AEP	2,779.5	692.9	80.0%	20.0%	2,644.9	489.6	84.4%	15.6%
APS	19.0	486.0	3.8%	96.2%	0.5	414.9	0.1%	99.9%
ATSI	1,327.2	1,840.3	41.9%	58.1%	1,640.3	2,030.8	44.7%	55.3%
BGE	0.0	972.3	0.0%	100.0%	0.0	300.7	0.0%	100.0%
COMED	3,222.5	0.0	100.0%	0.0%	1,586.5	0.0	100.0%	0.0%
DAY	0.0	234.9	0.0%	100.0%	0.0	255.3	0.0%	100.0%
DOM	8,481.8	3.7	100.0%	0.0%	7,053.2	7.6	99.9%	0.1%
DPL	166.0	107.1	60.8%	39.2%	384.4	156.7	71.0%	29.0%
DUKE	0.0	647.6	0.0%	100.0%	192.1	1,175.8	14.0%	86.0%
DUQ	0.0	178.9	0.0%	100.0%	0.0	133.7	0.0%	100.0%
EKPC	0.0	104.1	0.0%	100.0%	0.0	93.0	0.0%	100.0%
JCPL	0.0	0.0	NA	NA	0.0	0.0	NA	NA
MEC	19.5	10.9	64.1%	35.9%	0.0	0.0	NA	NA
PE	174.5	369.7	32.1%	67.9%	97.1	10.5	90.2%	9.8%
PECO	424.1	0.0	100.0%	0.0%	10.1	0.0	100.0%	0.0%
PEPCO	0.0	427.8	0.0%	100.0%	0.0	151.5	0.0%	100.0%
PPL	0.0	0.0	NA	NA	0.0	0.0	NA	NA
PSEG	0.0	0.0	NA	NA	0.0	0.0	NA	NA
TOTAL	16,614.1	6,076.3	73.2%	26.8%	13,609.1	5,220.1	72.3%	27.7%

Figure 13-1 shows the predicted and estimated impact of Stage 1A infeasibilities on FTR funding for the 2012/2013 through 2024/2025 planning periods, as well as the predicted impact on funding for the 2025/2026 planning period. The predicted funding is based on the infeasible ARR MW and the nodal price of the source and sink in the Annual FTR Auction. The estimated funding is calculated assuming every infeasible ARR MW is self scheduled, and uses the hourly congestion LMP values of the applicable day-ahead hours. The large estimated funding impact in the 2024/2025 planning period was a result of the relatively large overallocation of Stage 1A ARRs (and related FTRs) relative to expected congestion on Stage 1A related paths (Figure 13-13).

Figure 13-1 Stage 1A Infeasibility funding impact

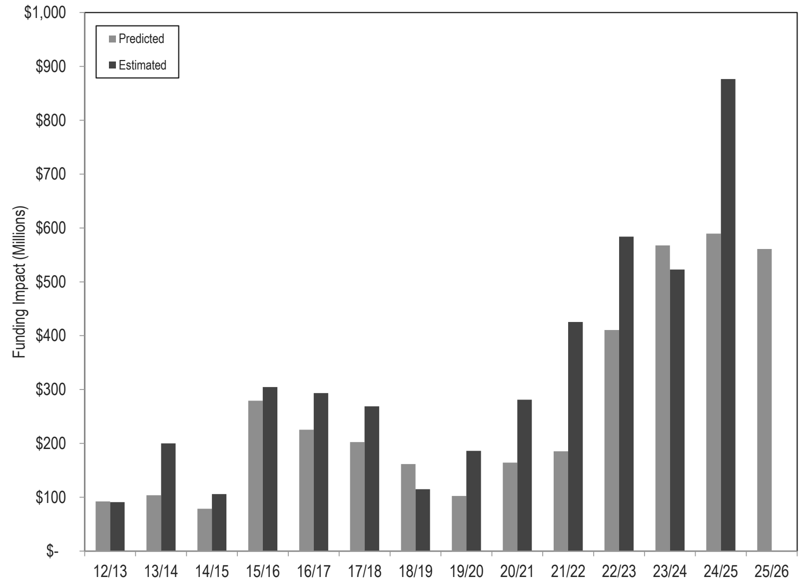


Table 13-7 shows the MW of retired generation sources for Stage 1A ARRs, the Qualified Replacement Resource (QRR) MW assigned by PJM for all resources and the replacement MW that were considered rate based. A rate based unit is a replacement generator that is owned by the ARR holder, or subject to firm energy and capacity supply contracts.[21] The term rate based is a misleading reference to the premarket cost of service regulation paradigm. If PJM does not find such a unit, PJM will use another unit that is close to where the retired unit was located even if it is not owned or under contract.

21 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025) at 21.

Table 13-7 Qualified Replacement Resource (QRR) results: 2025/2026 planning period

Zone	Historical Retired	Replacement (All)	Replacement (Rate-based)
ACEC	1,779.8	1,056.5	59.0
AEP	8,330.2	7,776.4	1,839.7
APS	3,315.5	3,456.2	97.2
ATSI	7,154.3	4,642.1	36.7
BGE	1,360.0	867.0	0.0
COMED	8,503.8	6,423.1	4.5
DAY	2,416.5	263.4	6.4
DOM	5,996.6	6,380.1	5,333.9
DPL	976.7	445.6	218.3
DUKE	3,234.5	2,029.2	57.6
DUQ	1,301.0	811.7	0.0
EKPC	198.1	229.3	0.0
JCPL	2,137.1	1,373.2	0.0
OVEC	0.0	459.2	1,854.0
MEC	1,082.0	1,059.4	0.0
PE	1,606.5	1,570.3	0.1
PECO	1,432.3	1,077.0	0.0
PEPCO	3,726.0	2,030.3	0.0
PPL	1,224.3	779.6	0.0
PSEG	5,093.2	3,177.0	0.0
REC	0.0	0.0	0.0
Total	60,868.5	45,906.6	9,507.4

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, an LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs and residual ARRs within the control zone based on the shifted load.[22] ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. The reassignment of positively valued ARRs supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

22 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

Table 13-8 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred from June 1, 2024, through September 30, 2025.

There were 16,509 MW of ARRs associated with $385.7 thousand of revenue that were reassigned for the first four months of the 2025/2026 planning period. There were 32,594 MW of ARRs associated with $1,187.6 thousand of revenue that were reassigned for the 2024/2025 planning period.

Table 13-8 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2024 through September 2025

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2024/2025 (12 months)	2025/2026 (4 months)	2024/2025 (12 months)	2025/2026 (4 months)
ACEC	300	133	$4.2	$0.6
AEP	3,427	1,786	$64.9	$16.0
APS	1,666	1,129	$75.8	$31.1
ATSI	4,572	2,667	$161.5	$42.8
BGE	2,408	1,166	$341.1	$94.8
COMED	2,975	907	$30.0	$15.6
DAY	1,298	672	$20.5	$6.9
DUKE	1,824	1,754	$106.6	$41.7
DUQ	1,437	752	$20.0	$3.4
DOM	689	232	$67.9	$15.2
DPL	288	146	$15.1	$10.1
EKPC	0	0	$0.0	$0.0
JCPLC	907	344	$11.4	$3.6
MEC	750	417	$30.1	$5.4
OVEC	0	0	$0.0	$0.0
PECO	3,020	1,573	$32.7	$9.8
PE	749	342	$42.2	$15.6
PEPCO	2,948	1,472	$66.5	$21.3
PPL	865	291	$21.4	$5.9
PSEG	2,320	684	$61.1	$45.2
REC	151	41	$2.7	$0.6
Total	32,594	16,509	$1,175.6	$385.7

Revenue

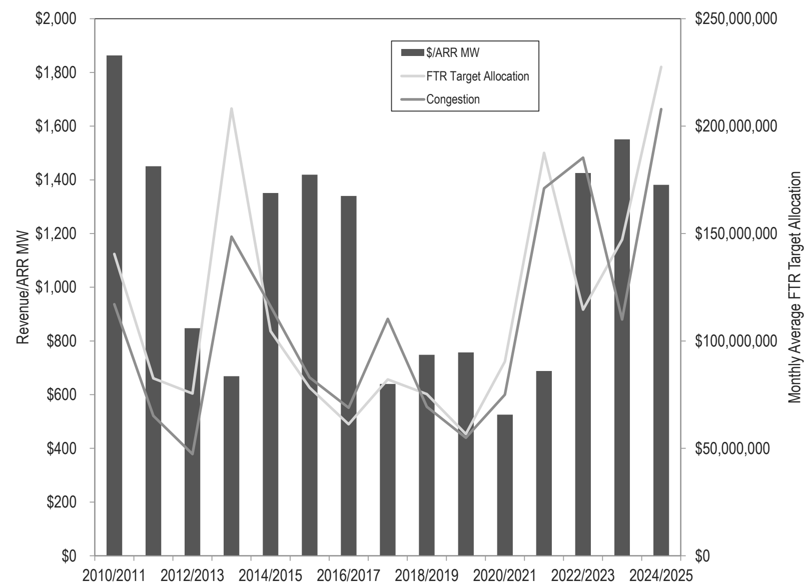
ARRs are allocated to qualifying customers rather than sold, so ARR revenue (target allocation) is different from the revenue that results from the FTR auctions, which generally exceeds the sum of the ARR target allocations.

Figure 13-2 shows the revenue per ARR MW held for each month of the 2010/2011 planning period through the 2024/2025 planning period. The revenue per ARR MW held does not include target allocation related payouts for self scheduled FTRs or surplus revenue, but does include Residual ARRs starting in August 2012.

PJM has had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. FTR prices increased in the 2014/2015 Annual FTR Auction in part as a result of reduced supply caused by PJM's assumption of more outages in the model relative to prior years. The decrease in system capability caused by PJM's more conservative modeling of the FTR market model reduced Stage 1B and Stage 2 ARR allocations. The increased FTR prices resulted in an increase in revenue per ARR MW, but there are fewer ARR MW. For the 2014/2015 planning period, the total dollars per MW of ARR allocation was $11,279, while the previous planning period resulted in revenue per MW of $6,692, a 68.5 percent increase in revenue per allocated ARR MW. Some of the ARR MW lost from proration were provided in the Residual ARR process, but the residual allocations are not comparable to the ARRs awarded in the annual process because residual ARR allocations change each month and cannot be self scheduled as FTRs. For the 2015/2016 and 2016/2017 planning periods, the revenue per MW of ARR allocation was $10,642 and $10,411. During these planning periods PJM chose more restrictive modeling criteria, which did not release the full capacity of the FTR model to account for revenue inadequacies. Beginning in the 2017/2018 planning period, when balancing congestion was removed from FTR funding, PJM reinstated less restrictive modeling criteria, and the revenue per MW of ARR decreased due to an increase in modeled capability. For the 2017/2018 and 2018/2019 planning periods the revenue per MW of ARR was $5,168 and $6,841. For the 2022/2023 planning period, cleared ARR MW decreased significantly (see Table 13-3) from the previous planning period, indicating that PJM again chose more restrictive modeling criteria for the FTR model to improve FTR funding. This results in fewer ARRs being awarded. Due to significant increases in FTR prices in the 2022/2023 planning period, the revenue per MW of ARR was $12,274. For the 2023/2024 planning period, FTR prices decreased compared to the 2022/2023 planning period and the revenue per MW of ARR was $14,463, a 17.8 percent decrease. For the 2024/2025 planning period PJM again used less restrictive modeling criteria in the FTR model, resulting in more ARRs being awarded. The revenue per MW of ARR decreased to $12,058, a 16.6 percent decrease.

Under the current rules, load is required to directly pay balancing congestion costs, not included in Figure 13-2, which reduce the revenue received by ARR holders. There is no support for the assertion made by proponents of shifting balancing congestion to load that higher ARR values would result, and there is no evidence of any kind that load is better off as a result of the arbitrary assignment of balancing congestion to load.

Figure 13-2 Revenue per ARR MW paid to ARR holders compared to congestion and FTR target allocations: 2010/2011 through 2024/2025 planning periods



ARR holders have limited options to pick source points for their ARRs. The holders of Stage 1A rights are limited to specific historical sources (or PJM defined replacement sources when resources retire). Of the stage 1A rights allocated to ARR holders, 58.5 percent were sourced within the ARR holder's zone in the 2024/2025 planning period. Table 13-4 shows that, for the 2025/2026 planning period, 78.6 percent of the ARR MW are based on generation inside the zone where the ARR load is located and 21.4 percent of the ARR MW are based on generation outside the zone where the ARR load is located. In contrast, only 15.5 percent of congestion resulted from constraints inside the zone where load is located and 84.5 percent of congestion resulted from constraints outside the zone where load is located during the 2024/2025 planning period. The primary source of a load zone's actual congestion is the result of transmission constraints that separate that zone from resources external to that zone, not by constraints internal to that zone. The congestion offset revenues per MW of internally sourced Stage 1A ARR rights are less than the revenue per MW of Stage 1A ARR rights from externally sourced resources. Table 13-9 shows the share of ARR revenue, by stage, for ARRs with paths that source inside or outside the zone where the load is located, for the 2025/2026 planning period. While 14.8 percent of all ARR MW are Stage 1A ARRs with sources outside the zone where load is located (see Table 13-4), those ARRs provide 26.2 percent of the total ARR revenues.

This illustrates one of the fundamental issues with the path based approach which originated in a cost of service design where most load was served by, or assumed to be served by, generation in the same zone as load. In fact, in the PJM market, which operates as an integrated network, a significant proportion of congestion is based on constraints that are not in the same zone as load. The path based approach does not and cannot reflect the actual congestion paid by load. The use of the path based approach is the fundamental source of the under assignment of congestion revenue rights to load in the ARR/FTR model.

Table 13-9 Share of ARR revenue that sources in/out of load zone: 2025/2026 planning period

	Stage 1A		Stage 1B		Stage 2		Total	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	39.2%	33.5%	3.2%	0.2%	13.7%	10.1%	56.1%	43.9%
AEP	17.9%	52.8%	0.6%	18.0%	6.0%	4.7%	24.5%	75.5%
APS	18.8%	66.7%	0.6%	9.8%	0.5%	3.6%	19.9%	80.1%
ATSI	63.8%	25.8%	0.2%	0.3%	1.2%	8.7%	65.2%	34.8%
BGE	81.9%	13.8%	2.8%	0.0%	0.9%	0.6%	85.6%	14.4%
COMED	0.0%	50.6%	0.0%	4.1%	(0.0%)	45.4%	(0.0%)	100.0%
DAY	78.1%	1.4%	4.1%	1.2%	11.6%	3.6%	93.8%	6.2%
DOM	0.7%	97.7%	0.0%	0.5%	0.0%	1.0%	0.7%	99.3%
DPL	26.3%	64.2%	1.8%	0.7%	1.3%	5.8%	29.3%	70.7%
DUKE	89.4%	9.3%	0.3%	0.5%	0.2%	0.2%	90.0%	10.0%
DUQ	87.1%	0.1%	0.8%	0.0%	11.1%	0.9%	99.0%	1.0%
EKPC	79.9%	0.0%	15.2%	0.0%	4.9%	0.0%	100.0%	0.0%
EXT	46.3%	0.0%	0.0%	0.0%	53.7%	0.0%	100.0%	0.0%
JCPL	15.1%	1.0%	19.7%	(0.0%)	64.0%	0.2%	98.8%	1.2%
MEC	11.3%	42.9%	5.1%	0.2%	6.9%	33.6%	23.3%	76.7%
OVEC	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%	0.0%
PE	20.8%	48.1%	0.0%	1.1%	0.3%	29.6%	21.1%	78.9%
PECO	(0.5%)	100.2%	(0.5%)	0.2%	0.5%	0.0%	(0.5%)	100.5%
PEPCO	89.3%	9.7%	0.0%	0.7%	0.0%	0.2%	89.3%	10.7%
PPL	(0.0%)	62.4%	(0.2%)	(0.4%)	1.8%	36.4%	1.5%	98.5%
PSEG	28.0%	51.4%	11.0%	0.1%	2.6%	7.0%	41.5%	58.5%
REC	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Total	26.2%	58.5%	1.3%	3.5%	1.9%	8.6%	29.4%	70.6%

ARR Target Allocations

Table 13-10 shows the monthly ARR target allocations from Annual ARRs and Residual Residual ARRs for the first four months of the 2025/2026 planning period and the entire 2024/2025 planning period. Table 13-10 also shows the FTR auction revenue available to fund ARR target allocations. Annual ARR target allocations (Table 13-10) are based on the nodal clearing prices from FTR obligations in the Annual FTR Auction. The annual ARR target allocation is divided evenly among every day of the planning period. Residual ARR target allocations (Table 13-10) are based on the nodal clearing prices from FTR obligations in the monthly FTR auctions and vary each month.

In the first four months of the 2025/2026 planning period, total ARR target allocations (the sum of annual and residual ARR target allocations) were $664,369,697, up 36.3 percent from $487,592,678 in the same period of the 2024/2025 planning period. Total ARR target allocations in the first four months of the 2025/2026 planning period include $613,835,777 annual ARR target allocations (up 27.3 percent relative the same period of the 2024/2025 planning period) and $50,533,920 Residual ARR target allocations (up 819.0 percent relative to the same period of the 2024/2025 planning period). In the first four months of the 2025/2026 planning period FTR auction revenue available to pay FTR was $702,778,731, up 28.0 percent from $548,979,997 in the same period of the 2024/2025 planning period. The significant and unprecedented increase in Residual ARR target allocations compared to Annual ARR target allocations and FTR Auction Revenue led to the first month with an ARR deficiency in the history of the ARR market. In July 2025 there was a $229,526 deficiency for ARR holders. PJM's monthly auction process does not consider the impact of Residual ARR target allocation when the Monthly FTR Auctions are optimized and cleared.

Table 13-10 Monthly ARR target allocations compared to FTR auction revenue: 2024/2025 and 2025/2026 planning periods

Month	Annual ARR Target Allocations	Residual ARR Target Allocations	Total ARR Target Allocations	FTR Auction Revenue	ARR Surplus or Deficiency
Jun-24	$118,548,955	$1,542,269	$120,091,225	$133,459,438	$13,368,213
Jul-24	$122,500,587	$817,746	$123,318,333	$139,272,100	$15,953,768
Aug-24	$122,500,587	$2,192,686	$124,693,273	$140,450,805	$15,757,532
Sep-24	$118,548,955	$940,983	$119,489,938	$135,797,655	$16,307,717
Oct-24	$122,500,587	$675,276	$123,175,863	$142,077,688	$18,901,826
Nov-24	$118,548,955	$389,592	$118,938,547	$137,582,288	$18,643,741
Dec-24	$122,500,587	$1,423,964	$123,924,551	$142,273,691	$18,349,140
Jan-25	$122,500,587	$3,351,831	$125,852,418	$141,776,870	$15,924,451
Feb-25	$110,645,692	$9,503,030	$120,148,721	$128,790,514	$8,641,793
Mar-25	$122,500,587	$1,258,883	$123,759,470	$141,476,041	$17,716,571
Apr-25	$118,548,955	$3,845,490	$122,394,445	$138,463,040	$16,068,595
May-25	$122,500,587	$367,497	$122,868,084	$143,447,210	$20,579,127
Summary For Planning Period 2024/2025					
Total	$1,442,345,621	$26,309,246	$1,468,654,867	$1,664,867,340	$196,212,473
Jun-25	$150,943,224	$12,903,832	$163,847,056	$170,292,924	$6,445,867
Jul-25	$155,974,665	$23,175,461	$179,150,126	$178,920,600	($229,526)
Aug-25	$155,974,665	$13,502,528	$169,477,193	$179,519,198	$10,042,005
Sep-25	$150,943,224	$952,098	$151,895,322	$174,046,010	$22,150,688
Summary For Planning Period 2025/2026*					
Total	$613,835,777	$50,533,920	$664,369,697	$702,778,731	$38,409,034

*First four months of the 2025/2026 planning period

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs can only be allocated to participants whose ARRs were prorated in Stage 1B and only to a maximum of the prorated reduction, so not all available Residual ARRs are allocated. Residual ARRs are automatically assigned to eligible participants the month before the effective date, are effective for a single month and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations for FTRs of the same period purchased the relevant monthly auctions, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation. For the following planning period, these Residual

ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[23] In prior planning periods, PJM's modeling of excess outages in order to manage FTR market outcomes resulted in the allocation of some ARRs that would have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-11 shows the Residual ARRs allocated to participants and the associated target allocations. The available volume is the total additional capacity available to be allocated as Residual ARRs. The cleared volume is the residual ARR capacity actually allocated to participants with prorated ARRs based on the level of prorated ARRs in Stage 1B and the affected paths. In the first four months of the 2025/2026 planning period, PJM allocated a total of 15,233.8 MW of Residual ARRs with a target allocation of $50.5 million. In the same period of the 2024/2025 planning period, PJM allocated a total of 7,998.2 MW of residual ARRs with a target allocation of $5.5 million. The 819.9 percent increase in target allocations for Residual ARRs without a corresponding increase in monthly FTR auction revenue (See Table 13-43) in the first four months of the 2025/2026 planning period led to the ARR deficiency in July 2025.

Table 13-11 Residual ARR allocation volume and target allocation: 2014/2015 planning period through 2025/2026 planning period

Planning Period	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
2014/2015	65,095.3	22,532.9	34.6%	$8,160,918.27
2015/2016	61,807.0	37,042.4	59.9%	$8,620,353.27
2016/2017	71,000.7	35,034.9	49.3%	$6,986,723.44
2017/2018	81,040.8	39,597.4	48.9%	$17,497,625.78
2018/2019	49,646.9	27,335.6	55.1%	$11,817,002.00
2019/2020	48,286.5	27,233.2	56.4%	$12,369,580.58
2020/2021	43,484.2	25,028.0	57.6%	$11,677,033.36
2021/2022	46,092.0	27,619.2	59.9%	$18,806,123.46
2022/2023	71,068.9	34,502.8	48.5%	$38,140,961.08
2023/2024	81,055.2	27,055.0	33.4%	$8,721,412.56
2024/2025	128,523.3	36,097.6	28.1%	$26,309,245.50
2025/2026*	43,477.7	15,233.8	35.0%	$50,533,920.18

*First four months of 2025/2026 planning period

23 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

IARRs

In theory, Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to result in IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[24]

There are three sources of IARRs: IARRs based on a specific transmission investment; IARRs based on merchant transmission or generation interconnection projects; and IARRs based on RTEP upgrades. In the case of a specific transmission investment, the participant elects desired IARR MW between a specified source and sink and PJM and the affected transmission owners determine the upgrades necessary to create incremental capability.[25] In the other two cases, the participants paying for the upgrades are assigned IARRs if any are created. IARR requests have resulted in 12 unique source and sink combinations, totaling 1,887.2 MW of IARR paths.

The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Maintaining the IARR process impedes the search for real solutions. PJM's process for creating and assigning IARRs is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[26]

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions be available upon request to the party that pays for such upgrades or expansions.[27] Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights,

24 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.
25 See Attachment EE of the PJM Open Access Transmission Tariff <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>.
26 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").
27 *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶ 61,077 (2006) ("Order No. 681"), *order on reh'g*, Order No. 618-A, 117 FERC ¶ 61,201 (2006), *order on reh'g*, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

which are given first and absolute priority in PJM's annual allocation process. Granting Stage 1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. If the annual market model used to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

The MMU recommends that IARRs be eliminated from the PJM tariff. If IARRs are not eliminated, the MMU recommends that IARRs be subject to prorating like all other ARR rights rather than being exempt from prorating.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the day-ahead energy market across specific FTR transmission paths. These day-ahead congestion price differences (shadow prices), multiplied by the FTR position in MW, are termed the FTR target allocations. The FTR target allocations define the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to make payments rather than receive revenues in the FTR market. One of the fundamental flaws in the FTR design is the mismatch between congestion and the differences in day-ahead prices between nodes. The difference in day-ahead congestion prices is not congestion. Target allocations are not congestion. It is this fundamental flaw that creates what PJM refers to as "underfunding" or "revenue inadequacy." If FTRs were the rights to congestion revenue, there could never be revenue inadequacy. Congestion payments to FTR holders would always exactly equal congestion revenues.

Under the current rules, the revenue available to pay FTR holders' target allocations in a given month includes day-ahead congestion, payments by holders of negatively valued FTRs, and FTR auction revenues greater than ARR target allocations. Any such revenue above FTR target allocations from prior months in a planning period are used to pay any current month shortfalls. Payments to FTR holders for each planning period cannot exceed the target allocations because the target allocations define the FTR product purchased. At the end of each planning period, any surplus revenue above the target allocations is distributed to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. For example, if the payout ratio is less than 1.0 at the end of the planning period, the payments to all FTRs are reduced. Payments are made pro rata based on target allocations. The result is widespread cross subsidies because assignment of path specific FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. At the end of a planning period, if the total revenue is less than the total target allocations, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period, based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning period.

Auction market participants may offer to buy FTRs between any eligible pricing nodes on the system, as defined by PJM for each auction. For the Annual FTR Auction and FTRs bought in the monthly auctions, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. For the Long Term FTR Auction there is a smaller set of available hubs, control zones, aggregates, generator buses and interface pricing points available. PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW.

FTRs are bought from supply defined by PJM. The fact that load is selling congestion revenue rights is not recognized in the FTR design, although FTR buyers can resell FTRs at a price they agree to accept. Load has no role in defining the price at which PJM sells FTRs on their behalf. Load has no role in deciding the total FTR MW to be sold. Load has no role in deciding whether to sell load's rights to congestion revenues. PJM's objective in the FTR auctions is to maximize auction revenue, based only on the total set of bid prices and bid MW, but absent reservation prices from load. The failure to allow sellers the ability to decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction net revenue and that the FTR market is not really a market.

Once bought from PJM, FTRs can be bought and sold. Buy bids are bids to buy FTRs in the auctions. Sell offers are offers to sell existing FTRs in the auctions.

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. Prior to June 30, 2024, there was no requirement to report accurate detailed information about bilateral transactions settled through PJM billing systems. Effective June 30, 2024, the Commission accepted PJM's proposed revisions to the rules that required the reporting of bilateral price information and corroborating contract documents of any bilateral change of FTR ownership between participants/accounts that is settled through PJM settlement systems.[28] Bilateral transactions remain dependent on the contract established between the parties. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system.

Supply and Demand

Total FTR supply in each auction as defined by PJM is limited by the definition of the transmission system capacity included in the PJM FTR market model as modified, for example, by PJM assumptions about transmission outages, for which there are no clear rules. PJM may also limit available transmission capacity through subjective judgment exercised without any clear guidelines.

The FTR auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages.[29] In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model will generally have significant distributional consequences; they will affect different areas very differently. The fact that outages are modeled at significantly lower than historical levels results in selling too much FTR capacity, which creates downward pressure on ARR prices. To address this issue within the existing design, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual expected transmission capacity.

Long Term FTR Auctions

In July 2006, FERC approved Order No. 681 mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets. FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights."[30] Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design. Excess system capability in years two and three of the long term FTR auction is never made available to load in the form of ARRs and is only made available to FTR buyers.

PJM conducts the Long Term FTR Auction for the next three consecutive planning periods. The Long Term FTR Auction consists of five rounds beginning in June of the preceding planning period and continuing through March. FTRs

28 *See* 187 FERC ¶ 61,020.

29 See the *2022 Annual State of the Market Report for PJM*, Volume 2, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.

30 Order No. 681 at P 17.

purchased in prior rounds or Long Term Auctions may be offered for sale in subsequent rounds of the long term, annual or monthly FTR auctions. FTRs obtained in the Long Term FTR Auctions have terms of one year. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations, with FTR options unavailable in the Long Term FTR Auctions.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and uses the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The ARR requests are greater than the previously cleared ARRs. The difference between the requested ARRs and the ARR/FTR market model's transmission system capacity, both without outages, determines the residual capability offered in the Long Term FTR Auction. The revisions provide ARR holders with more congestion rights in the Long Term FTR Auction that will carry into the Annual FTR Auction.

But the revisions do not address the congestion revenue rights sold in years two and three of the Long Term FTR Auction, which remain unavailable to ARRs. As a result, the rights to significant congestion revenues are still assigned to the Long Term FTR Auction without ever having been made available to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design which is to return all congestion revenues to load.

Long Term FTR Auction transmission capacity is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction capability. Even this approach does not, and cannot, preserve all congestion revenues for ARR holders in the first year of the Long Term Auction due to changes in system topology and outage selection between planning periods. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction.

Annual FTR Auctions

Annual FTRs are effective for an entire planning period, June 1 through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM decides would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[31] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear, is not defined and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. The Annual FTR Auction consists of four rounds that allow any PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in the auctions include obligations and options and 24 hour, peak, off peak, and weekend peak products. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Monthly Balance of Planning Period FTR Auctions

Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Beginning with the 2020/2021 planning period, market participants can bid for or offer monthly

31 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

FTRs for any of the remaining individual calendar months in the planning period. FTRs in the auctions include obligations and options and 24 hour, peak, off peak, and weekend peak products.[32]

Bilateral Market

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Prior to June 30, 2024, there was no requirement to report accurate detailed information about bilateral transactions settled through PJM billing systems. Effective June 30, 2024, the Commission accepted PJM's proposed revisions to the rules that required the reporting of bilateral price information and corroborating contract documents of any bilateral change of FTR ownership between participants/accounts that is settled through PJM settlement systems.[33] Bilateral transactions remain dependent on the contract established between the parties.

For bilateral trades reported to PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. Bilateral FTRs reported to PJM can also include more restrictive start and end times, meaning that the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time. Once the bilateral transaction is reported to PJM, PJM transfers ownership and adjusts credit requirements accordingly. Participants have used bilateral trades reported to PJM to reduce their credit requirements.

PJM's revised rules related to bilateral contracts fail to address the impact of PJM's indemnification rules. PJM stated that the "maintenance of the assumption of risk and costs is not a continuing interest in the FTR once sold; a continuing interest would be a right or benefit with respect to the subject FTR that survives the bilateral transaction." Contrary to logic, PJM asserts that only positive interests count as interests. Assumption of risks and costs of an FTR is, by definition, assumption of a financial interest in an FTR. When a participant buys an FTR in an auction, they assume the risks and costs of the FTR. Under PJM's indemnification rules the participant that bilaterally trades an FTR retains risks and costs associated with that FTR. Under PJM's indemnification rules, a bilateral seller of an FTR therefore has a continuing direct financial interest in that FTR and a direct financial interest in the credit and collateral of the buyer.

PJM's FTR market is the most transparent of all PJM markets. The facilitation of confidential bilateral transactions undercuts that transparency and therefore the efficiency of the FTR market. The bilateral information would be provided solely to PJM and not to the market. Transparency for PJM alone is not market transparency. The facilitation of confidential bilateral transactions does nothing to advance or improve the basic function of FTR markets.

There is no reason to continue to permit bilateral transactions outside the PJM FTR market. The MMU recommends that the bilateral FTR transactions market be eliminated and that all FTR transactions should take place in the FTR auctions, in order to provide full transparency, effective price discovery, and to minimize risk to market participants and PJM members.[34] The bilateral FTR market provides a PJM facilitated mechanism that undermines transparency for market participants and for loads whose congestion revenues fund FTRs. Bilateral FTR trading outside of PJM's transparent FTR market is inefficient, inconsistent with the basic structure and purpose of the PJM FTR market, and creates unnecessary credit risk.

Market Structure

In order to evaluate the ownership of FTRs, the MMU categorizes all participants owning FTRs in PJM as either physical or financial. The MMU modified the method for categorizing participants as physical and financial participants. Prior to the *2025 Quarterly State of the Market Report for PJM: January*

32 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).
33 *See* 187 FERC ¶ 61,020.
34 See Protest of the Independent Market Monitor for PJM, Docket No. ER24-374-000 (November 30, 2023); Comments of the Independent Market Monitor for PJM, Docket No. ER24-374-000 (February 6, 2024).

through March, participants were defined as either physical or financial at an organization level. Under the modified approach, physical entities are defined as individual accounts in PJM's settlement systems that take physical positions in PJM markets and typically include utilities and customers. Financial entities are defined as individual accounts in PJM's settlement systems that take financial positions in PJM markets and typically include banks and trading firms. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-12 shows the 2025/2028 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 92.7 percent of prevailing flow buy bid FTRs and 96.8 percent of counter flow buy bid FTRs with the result that financial entities purchased 94.7 percent of all long term FTR auction cleared buy bids. Physical entities purchased 5.3 percent of all cleared long term FTRs in the 2025/2028 Long Term FTR Auction, down 1.0 percentage points from the previous Long Term FTR Auction.

Table 13-12 Long term FTR auction patterns of ownership by FTR direction: 2025/2028 auction

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	7.3%	3.2%	5.3%
	Financial	92.7%	96.8%	94.7%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	0.2%	0.2%	0.2%
	Financial	99.8%	99.8%	99.8%
	Total	100.0%	100.0%	100.0%

Table 13-13 shows the HHI for the individual periods in the 2017/2020 through 2025/2028 Long Term FTR Auctions and the entire auction. The YRALL auction was highly concentrated until its removal in the 2020/2023 Long Term Auction. The individual annual auctions are unconcentrated with the exception of years two and three of the 2017/2020 Auction and year three of the 2023/2026 Auction.

Table 13-13 Long term HHIs by auction

Auction	YR1	YR2	YR3	YRALL	Entire Auction
17/20 Long Term Auction	779	1779	1354	8533	884
18/21 Long Term Auction	711	940	749	8654	693
19/22 Long Term Auction	492	647	768	9954	506
20/23 Long Term Auction	567	575	638	NA	463
21/24 Long Term Auction	495	535	767	NA	460
22/25 Long Term Auction	518	626	888	NA	598
23/26 Long Term Auction	496	713	1049	NA	644
24/27 Long Term Auction	473	656	949	NA	592
25/28 Long Term Auction	485	603	786	NA	553

Table 13-14 shows the annual FTR auction cleared FTRs for the 2025/2026 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2025/2026 planning period, financial entities purchased 89.6 percent of prevailing flow FTRs, down 0.9 percentage points, and 97.8 percent of counter flow FTRs, up 0.5 percentage points, with the results that financial entities purchased 93.0 percent, unchanged, of all annual FTR auction cleared buy bids for the 2025/2026 planning period.

Table 13-14 Annual FTR Auction patterns of ownership by FTR direction: 2025/2026 planning period

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	3.8%	0.0%	2.2%
		No	6.6%	2.2%	4.8%
		Total	10.4%	2.2%	7.0%
	Financial	No	89.6%	97.8%	93.0%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		0.7%	1.9%	1.2%
	Financial		99.3%	98.1%	98.8%
	Total		100.0%	100.0%	100.0%

Table 13-15 shows the HHI values for cleared buy and self scheduled bids for the 2016/2017 through 2025/2026 Annual FTR Auctions. Obligation buy bids are consistently unconcentrated, while Option buy bids are unconcentrated to moderately concentrated. Cleared self scheduled bids are always highly concentrated.

Table 13-15 Annual auction HHIs by auction

Auction	Offset Type	Trade Type	HHI
25/26 Annual Auction	Obligation	Buy	425
	Obligation	SelfScheduled	2,650
	Option	Buy	815
24/25 Annual Auction	Obligation	Buy	399
	Obligation	Self Scheduled	2,975
	Option	Buy	822
23/24 Annual Auction	Obligation	Buy	425
	Obligation	Self Scheduled	2,595
	Option	Buy	1,220
22/23 Annual Auction	Obligation	Buy	424
	Obligation	Self Scheduled	3,398
	Option	Buy	884
21/22 Annual Auction	Obligation	Buy	420
	Obligation	Self Scheduled	3,291
	Option	Buy	957
20/21 Annual Auction	Obligation	Buy	278
	Obligation	Self Scheduled	2,970
	Option	Buy	1,299
19/20 Annual Auction	Obligation	Buy	251
	Obligation	Self Scheduled	2,661
	Option	Buy	978
18/19 Annual Auction	Obligation	Buy	357
	Obligation	Self Scheduled	2,620
	Option	Buy	1,213
17/18 Annual Auction	Obligation	Buy	303
	Obligation	Self Scheduled	2,794
	Option	Buy	2,099

Table 13-16 presents the monthly balance of planning period FTR auction cleared FTRs for the first four months of the 2025/2026 planning period by trade type, organization type and FTR direction. Financial entities purchased 95.3 percent of prevailing flow FTRs, up 2.2 percentage points, and 97.7 percent of counter flow FTRs, up 2.0 percentage points, from the same period of the 2024/2025 planning period, with the result that financial entities purchased 96.4 percent, up 2.2 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction for the first four months of the 2025/2026 planning period.

Table 13-16 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: 2025/2026 planning period

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	4.7%	2.3%	3.6%
	Financial	95.3%	97.7%	96.4%
	Total	100.0%	100.0%	100.0%
Sell	Physical	0.4%	0.4%	0.4%
	Financial	99.6%	99.6%	99.6%
	Total	100.0%	100.0%	100.0%

Table 13-17 shows the monthly cumulative HHI values for cleared obligation MW for the first four months of the 2025/2026 planning period monthly auctions for prevailing flow FTRs. Ownership of cleared prevailing flow bids was unconcentrated in 100 percent of auction periods.[35]

Table 13-17 Monthly Balance of Planning Period FTR Auction HHIs by period for prevailing flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-25	469	480	475	619	792	704	615	580	586	732	731	812
Jul-25		478	495	611	718	673	618	606	590	665	639	736
Aug-25			478	689	741	749	687	606	587	723	695	833
Sep-25				592	730	756	693	588	591	750	736	875

Table 13-18 shows the monthly cumulative HHI values for cleared obligation MW for the first four months of the 2025/2026 planning period monthly auctions by month for counter flow FTRs. Ownership of cleared counter flow bids was unconcentrated in 47.6 percent of periods and moderately concentrated in 52.4 percent of auction periods.

Table 13-18 Monthly Balance of Planning Period FTR Auction HHIs by period for counter flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-25	694	734	769	991	1071	1024	1079	1020	1123	1029	1185	1156
Jul-25		597	789	943	1026	1004	999	1060	1042	1012	1155	1096
Aug-25			672	914	990	982	960	1041	1014	962	1064	1042
Sep-25				685	938	932	903	1014	988	963	1036	1009

35 See *2025 Quarterly State of the Market Report for PJM: January through September*, Section 3: Energy Market, Competitive Assessment for HHI definitions.

Table 13-19 shows the average daily FTR ownership for all FTRs for the first four months of the 2025/2026 planning period by organization type, by FTR direction and self scheduled FTRs. Financial entities owned 82.5 percent of all prevailing flow FTR MW, up 0.8 percentage points, and 95.7 percent of all counterflow FTR MW, up 1.7 percentage points, from the same period of the 2024/2025 planning period, with the result that financial entities purchased 88.7 percent, up 1.7 percentage points, of all prevailing flow and counter flow FTR MW for FTRs effective in the first four months of the 2025/2026 planning period.

Table 13-19 Daily FTR held position ownership by FTR direction: June through May, 2024/2025 planning period

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	10.8%	4.3%	7.8%
Physical Self Scheduled	6.7%	0.0%	3.6%
Financial	82.5%	95.7%	88.7%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR market, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits in the FTR auction model. If, in PJM's judgment, the normal transmission limit is not consistent with revenue adequacy goals and simultaneous feasibility, then transmission limits are reduced pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[36] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow bids without being required to clear the corresponding prevailing flow bids.[37] The use of both of these procedures is contingent on the conditions that: PJM actions not affect the revenue adequacy of allocated ARRs; all requested self scheduled FTRs clear; and net FTR auction revenue is positive.

Long Term FTR Auction

In the 2025/2028 Long Term FTR Auction, 465,963 MW (23.5 percent of bid volume; 50.4 percent of total FTR volume) of counter flow FTR buy bids cleared, an increase from 304,456 MW and an increase from 47.7 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 457,906 MW (9.6 percent of bid volume; 49.6 percent of total FTR volume) an increase from 334,216 MW and a decrease from 52.3 percent of total FTR volume. In the 2025/2028 Long Term FTR Auction, 57,108 MW (8.5 percent) of counter flow sell offers and 111,744 MW (12.6 percent) of prevailing flow sell offers cleared.

Table 13-20 Long Term FTR Auction market volume: 2025/2028 auction

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	242,087	796,792	203,768	25.6%	593,024	74.4%
		Year 2	185,209	618,940	134,421	21.7%	484,519	78.3%
		Year 3	158,723	564,607	127,774	22.6%	436,833	77.4%
		Total	586,019	1,980,339	465,963	23.5%	1,514,376	76.5%
	Prevailing Flow	Year 1	453,306	1,977,093	223,305	11.3%	1,753,789	88.7%
		Year 2	302,885	1,496,082	133,992	9.0%	1,362,090	91.0%
		Year 3	241,022	1,276,086	100,610	7.9%	1,175,476	92.1%
		Total	997,213	4,749,261	457,906	9.6%	4,291,355	90.4%
	Total		1,583,232	6,729,600	923,869	13.7%	5,805,731	86.3%
Sell offers	Counter Flow	Year 1	107,516	343,079	35,956	10.5%	307,123	89.5%
		Year 2	79,437	222,290	16,007	7.2%	206,284	92.8%
		Year 3	33,875	103,697	5,145	5.0%	98,552	95.0%
		Total	220,828	669,067	57,108	8.5%	611,958	91.5%
	Prevailing Flow	Year 1	120,708	496,953	64,811	13.0%	432,142	87.0%
		Year 2	77,520	306,273	38,556	12.6%	267,717	87.4%
		Year 3	26,584	85,163	8,377	9.8%	76,786	90.2%
		Total	224,812	888,388	111,744	12.6%	776,645	87.4%
	Total		445,640	1,557,455	168,852	10.8%	1,388,603	89.2%

Figure 13-3 shows the percent of FTR MW cleared, and bid and cleared volume, by direction, for each round of the Long Term FTR Auction from the 2015/2018 through the 2025/2028 auctions.

36 See "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).
37 See *id.*

Figure 13-3 Long Term FTR Auction bid and cleared volume by round and direction

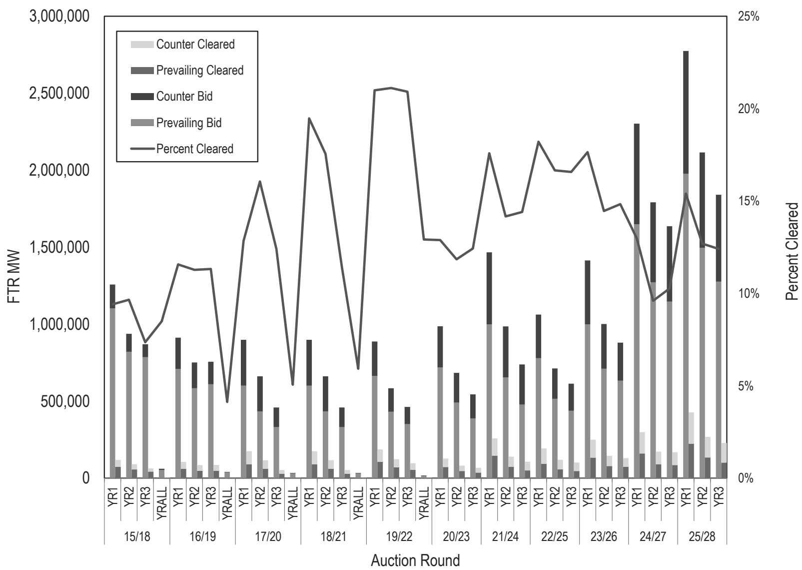


Table 13-21 compares cleared FTR obligations (not options) acquired in the Long Term FTR Auctions to the total cleared FTR obligations from the Annual FTR Auction, for FTRs in the 2014/2015 through 2025/2026 planning periods. A three year FTR is distributed to each individual planning period during its three year effective period. Long term FTRs that are effective in a single planning period were an average of 39.9 percent of total FTR volume in the 2014/2015 through 2025/2026 planning periods.

Table 13-21 Long Term and Annual Auction total cleared FTR MW

	Long Term FTR Product (Including YRALL)			Obligation Volume (MW)		
Effective Planning Period	YR3	YR2	YR1	Total Long Term	Annual (including self scheduled)	Long Term Percent of Total Cleared
2014/2015	81,666	86,754	131,911	300,330	356,522	45.7%
2015/2016	89,419	99,329	123,400	312,148	355,682	46.7%
2016/2017	97,837	95,637	107,182	300,656	397,258	43.1%
2017/2018	69,161	86,323	108,126	263,609	493,683	34.8%
2018/2019	87,232	109,827	176,998	374,057	549,669	40.5%
2019/2020	80,947	118,112	188,438	387,496	576,937	40.2%
2020/2021	54,451	125,330	127,054	306,835	525,550	36.9%
2021/2022	98,829	80,998	205,008	384,835	512,449	42.9%
2022/2023	67,603	120,621	193,268	381,492	467,194	45.0%
2023/2024	100,973	118,618	249,482	469,073	770,310	37.8%
2024/2025	101,674	144,699	298,773	545,146	944,669	36.6%
2025/2026	130,392	171,988	427,073	729,453	1,219,310	37.4%

Table 13-22 shows the MW proportion of FTRs by source and sink node type for cleared buy bids in the 2025/2028 Long Term FTR Auction. Generator to generator FTRs comprise 63.5 percent of all cleared FTR buy bids, up 1.6 percentage points from the 2024/2027 Long Term FTR Auction.

Table 13-22 Long Term FTR node type matrix: 2025/2028 auction

	Sink Type						
Source Type	Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	1.3%	6.9%	0.1%	0.2%	0.0%	0.2%	0.3%
Generator	6.3%	63.5%	2.1%	2.3%	0.4%	0.9%	2.6%
Hub	0.1%	0.6%	1.1%	0.1%	0.0%	0.1%	2.0%
Interface	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%
Load	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Residual Metered Aggregate	0.2%	1.4%	0.0%	0.0%	0.0%	0.0%	0.3%
Zone	0.3%	2.0%	1.0%	0.2%	0.0%	0.5%	2.1%

Annual FTR Auction

Table 13-23 shows the annual FTR auction market volume for the 2025/2026 Annual FTR Auction. Total FTR buy bids were 6,628,872 MW, up 39.8 percent from 4,741,013 MW for the previous Annual FTR Auction. For the 2025/2026 Annual FTR Auction 1,294,688 MW (19.5 percent) of buy bids cleared, up 29.6 percent from 999,108 MW (21.1 percent) for the previous Annual FTR Auction. There were 1,695,004 MW of sell offers, up 44.5 percent from 1,172,749 for the previous Annual FTR Auction. For the 2025/2026 Annual FTR Auction 183,410 MW (10.8 percent) of sell offers cleared, up 47.6 percent from 124,227 for the previous Annual FTR Auction. The total volume of cleared buy and self scheduled bids was 1,324,299 MW, up 28.8 percent from 1,028,420 MW in the previous Annual FTR Auction.

Table 13-23 Annual FTR Auction market volume: 2025/2026 auction

Trade Type	Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	378,977	1,930,773	549,391	28.5%	1,381,381	71.5%
		Prevailing Flow	673,791	3,556,006	640,307	18.0%	2,915,698	82.0%
		Total	1,052,768	5,486,779	1,189,699	21.7%	4,297,080	78.3%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	125,964	1,142,093	104,989	9.2%	1,037,104	90.8%
		Total	125,964	1,142,093	104,989	9.2%	1,037,104	90.8%
	Total	Counter Flow	378,977	1,930,773	549,391	28.5%	1,381,381	71.5%
		Prevailing Flow	799,755	4,698,099	745,297	15.9%	3,952,802	84.1%
		Total	1,178,732	6,628,872	1,294,688	19.5%	5,334,183	80.5%
Self-scheduled bids	Obligations	Counter Flow	126	48	48	100.0%	0	0.0%
		Prevailing Flow	8,762	29,563	29,563	100.0%	0	0.0%
		Total	8,888	29,611	29,611	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	379,103	1,930,821	549,440	28.5%	1,381,381	71.5%
		Prevailing Flow	682,553	3,585,569	669,870	18.7%	2,915,698	81.3%
		Total	1,061,656	5,516,390	1,219,310	22.1%	4,297,080	77.9%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	125,964	1,142,093	104,989	9.2%	1,037,104	90.8%
		Total	125,964	1,142,093	104,989	9.2%	1,037,104	90.8%
	Total	Counter Flow	379,103	1,930,821	549,440	28.5%	1,381,381	71.5%
		Prevailing Flow	808,517	4,727,662	774,860	16.4%	3,952,802	83.6%
		Total	1,187,620	6,658,483	1,324,299	19.9%	5,334,183	80.1%
Sell offers	Obligations	Counter Flow	149,725	735,729	69,606	9.5%	666,123	90.5%
		Prevailing Flow	185,040	925,637	113,145	12.2%	812,492	87.8%
		Total	334,765	1,661,366	182,751	11.0%	1,478,615	89.0%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	8,856	33,638	659	2.0%	32,979	98.0%
		Total	8,856	33,638	659	2.0%	32,979	98.0%
	Total	Counter Flow	149,725	735,729	69,606	9.5%	666,123	90.5%
		Prevailing Flow	193,896	959,275	113,804	11.9%	845,471	88.1%
		Total	343,621	1,695,004	183,410	10.8%	1,511,594	89.2%

Figure 13-4 shows the percent of FTR MW cleared and bid and cleared volume, by direction, for each round of the Annual FTR Auction from the 2015/2016 planning period through the 2025/2026 planning period.

Figure 13-4 Annual FTR Auction bid and cleared volume by round and direction

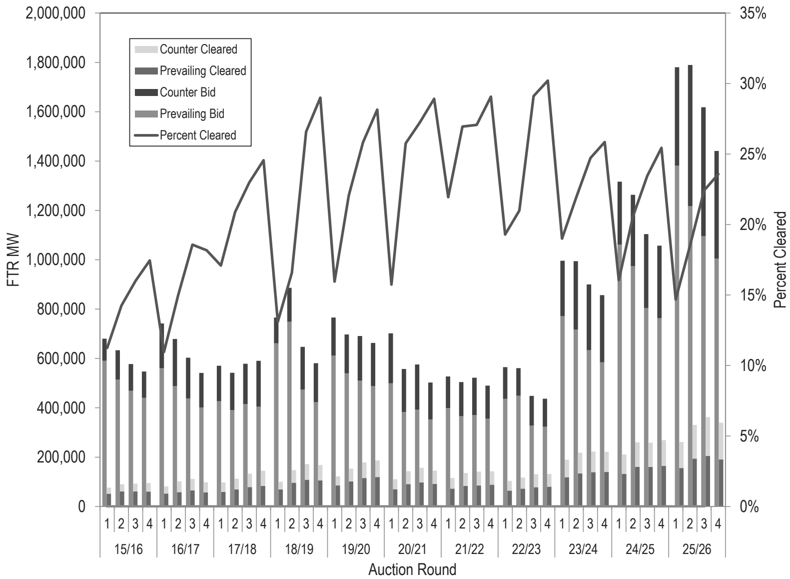


Figure 13-5 shows the proportion of ARRs self scheduled as FTRs for the last sixteen planning periods. The maximum possible level of self scheduled FTRs is equal to total ARRs. Eligible participants self scheduled 29,611MW (25.9 percent) of ARRs as FTRs for the 2025/2026 planning period, compared to 29,312 MW (25.3 percent) in the previous planning period.

Figure 13-5 Comparison of self scheduled FTRs: 2009/2010 through 2025/2026 planning periods

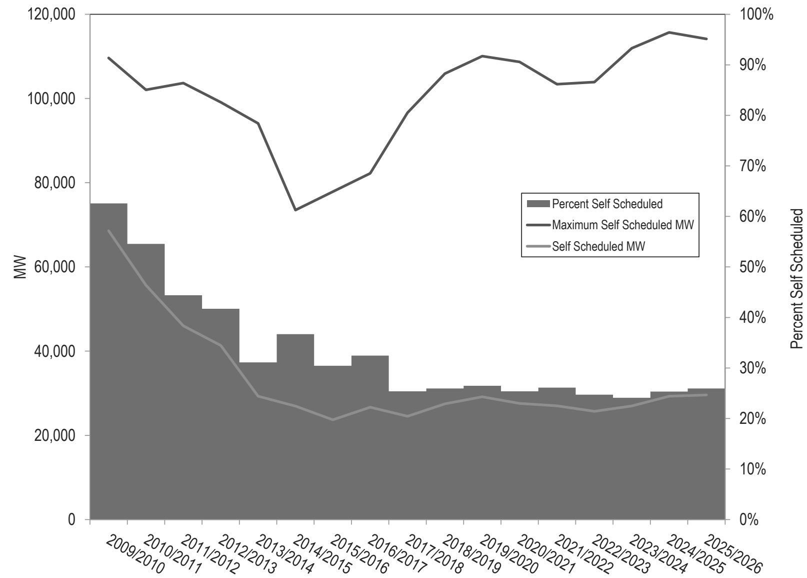


Table 13-24 shows the MW proportion of FTRs by source and sink node type for cleared buy and self scheduled bids in the 2025/2026 Annual FTR Auction.

Generator to generator FTRs comprise 60.1 percent of all cleared FTR buy and self scheduled bids in the 2025/20265 Annual Auction, up 2.4 percentage points from the previous planning period. Generator to generator FTRs make up a disproportionate share of total FTRs. Congestion results from load paying more for generation than generators receive. By definition, congestion is between generator sources and load sinks. Generator to generator paths do not represent the delivery of generation to load. FTRs between generators simply create a speculative opportunity because they can be a low cost or zero cost FTR in the current design with a significant payoff if there is a price difference between the two nodes.

The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load.

Table 13-24 Annual auction FTR node type matrix by proportion of MW: 2025/2026 auction

	Sink Type						
Source Type	Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	1.4%	6.5%	0.1%	0.1%	0.3%	0.5%	0.0%
Generator	10.5%	60.1%	2.3%	0.7%	3.3%	5.7%	0.1%
Hub	0.2%	1.0%	0.5%	0.0%	0.2%	1.2%	0.0%
Interface	0.0%	0.4%	0.0%	0.0%	0.1%	0.0%	0.0%
Load	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Residual Metered Aggregate	0.2%	0.9%	0.0%	0.0%	0.0%	0.1%	0.0%
Zone	0.4%	1.1%	0.7%	0.1%	0.3%	0.8%	0.0%

Monthly Balance of Planning Period Auctions

Table 13-25 provides the monthly balance of planning period FTR auction market volume for the first four months of the 2025/2026 and entire 2024/2025 planning periods. There were 35,598,375 MW of FTR obligation buy bids and 38,689,011 MW of FTR obligation sell offers for all bidding periods in the first four months of the 2025/2026 planning period.[38] The monthly balance of planning period FTR auction cleared 7,547,143 (21.8 percent) of FTR obligation buy bids and 4,481,377 MW (15.6 percent) of FTR obligation sell offers.

There were 14,314,021 MW of FTR option buy bids and 3,041,545 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2025/2026 planning period. The monthly balance of planning period FTR auction auctions cleared 462,972 MW (3.2 percent) of FTR option buy bids and 607,814 MW (20.0 percent) of FTR option sell offers.

38 The term obligation is used only to distinguish FTRs from options.

Table 13-25 Monthly Balance of Planning Period FTR Auction market volume: June 2025 through September 2025

Monthly Auction	Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jun-25	Obligations	Buy bids	1,524,117	10,459,179	1,857,497	17.8%	8,601,683	82.2%
		Sell offers	1,672,291	7,831,025	1,599,672	20.4%	6,231,353	79.6%
	Options	Buy bids	265,505	4,907,680	142,485	2.9%	4,765,195	97.1%
		Sell offers	151,286	726,502	183,122	25.2%	543,380	74.8%
Jul-25	Obligations	Buy bids	1,461,684	9,825,906	2,030,984	20.7%	7,794,922	79.3%
		Sell offers	1,608,014	7,053,811	1,108,932	15.7%	5,944,879	84.3%
	Options	Buy bids	192,280	4,109,077	129,501	3.2%	3,979,576	96.8%
		Sell offers	167,051	839,164	151,938	18.1%	687,226	81.9%
Aug-25	Obligations	Buy bids	1,389,431	7,505,218	1,905,638	25.4%	5,599,580	74.6%
		Sell offers	1,454,737	6,916,441	887,665	12.8%	6,028,776	87.2%
	Options	Buy bids	148,953	3,021,657	94,914	3.1%	2,926,743	96.9%
		Sell offers	146,719	772,381	144,017	18.6%	628,365	81.4%
Sep-25	Obligations	Buy bids	1,224,942	6,808,072	1,753,024	25.7%	5,055,048	74.3%
		Sell offers	1,374,215	6,887,734	885,108	12.9%	6,002,626	87.1%
	Options	Buy bids	128,052	2,275,607	96,071	4.2%	2,179,536	95.8%
		Sell offers	135,829	703,499	128,738	18.3%	574,761	81.7%
2024/2025*	Obligations	Buy bids	10,250,462	51,695,684	10,486,345	20.3%	41,209,339	79.7%
		Sell offers	10,167,424	40,510,062	5,622,983	13.9%	34,887,079	86.1%
	Options	Buy bids	756,191	15,283,383	757,379	5.0%	14,526,004	95.0%
		Sell offers	899,936	5,387,701	1,041,790	19.3%	4,345,912	80.7%
2025/2026**	Obligations	Buy bids	5,600,174	34,598,375	7,547,143	21.8%	27,051,233	78.2%
		Sell offers	6,109,257	28,689,011	4,481,377	15.6%	24,207,634	84.4%
	Options	Buy bids	734,790	14,314,021	462,972	3.2%	13,851,049	96.8%
		Sell offers	600,885	3,041,545	607,814	20.0%	2,433,731	80.0%

*Shows 12 months for 2024/2025 **Shows 4 months for 2025/2026

Figure 13-6 shows the bid volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auctions of the first four months of the 2025/2026 planning period. The prompt month is the final month for which FTRs for a specific month are sold. For example, June is the prompt month for June FTRs sold in the June auction, which occurs in May. The bid volume for the non-prompt months is significantly lower than for the prompt months. On average, the non-prompt month bid volume is 58.8 percent of the prompt month bid volume.

Figure 13-6 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June 2025 through September 2025 Auction

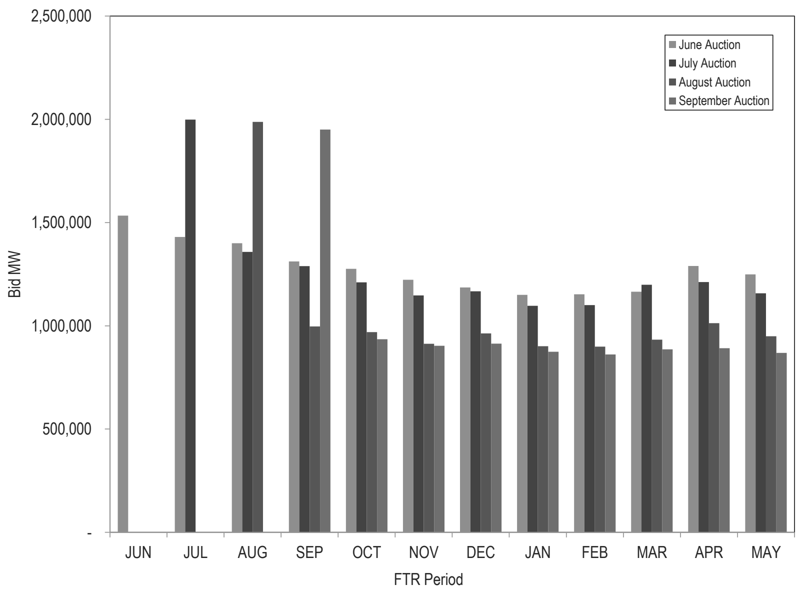


Figure 13-7 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June 2025 through September 2025 Auction

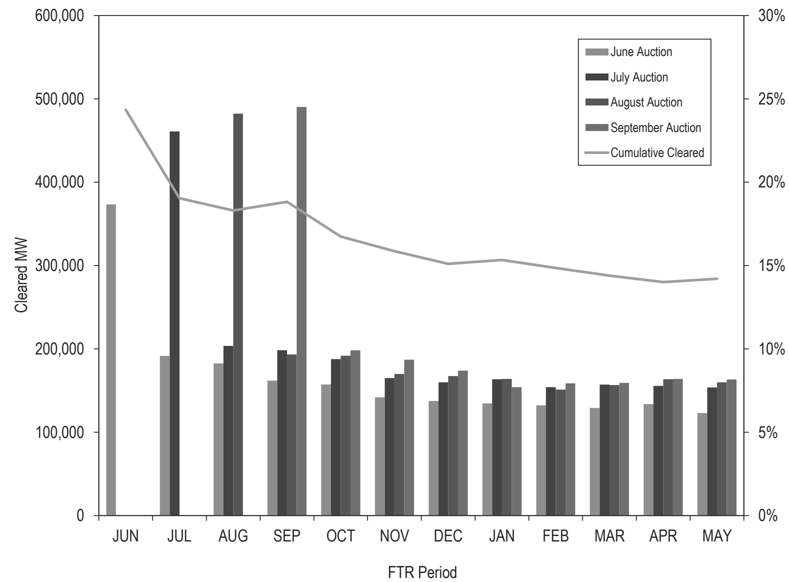


Figure 13-7 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auctions of the first four months of the 2025/2026 planning period. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt months cleared volume is 36.5 percent of the prompt month cleared volume.

Figure 13-8 shows the FTR bid, net bid and cleared volume from June 2003 through September 2025 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. Following the implementation of the Historical Simulation Initial Margining (HSIM) analysis model in the September 2022 Monthly Auction, bid and net bid volumes have increased significantly. On average in the first four months of the 2025/2026 planning period there was a 47.7 percent increase in bid volume and a 66.3 percent increase in net bid volume compared to the same month in the previous planning period.

Figure 13-8 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2025

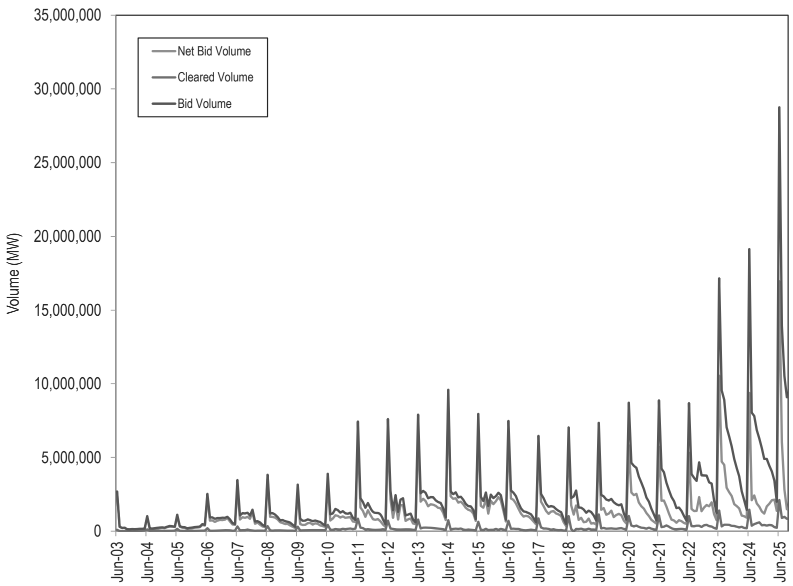


Figure 13-9 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through September 2025

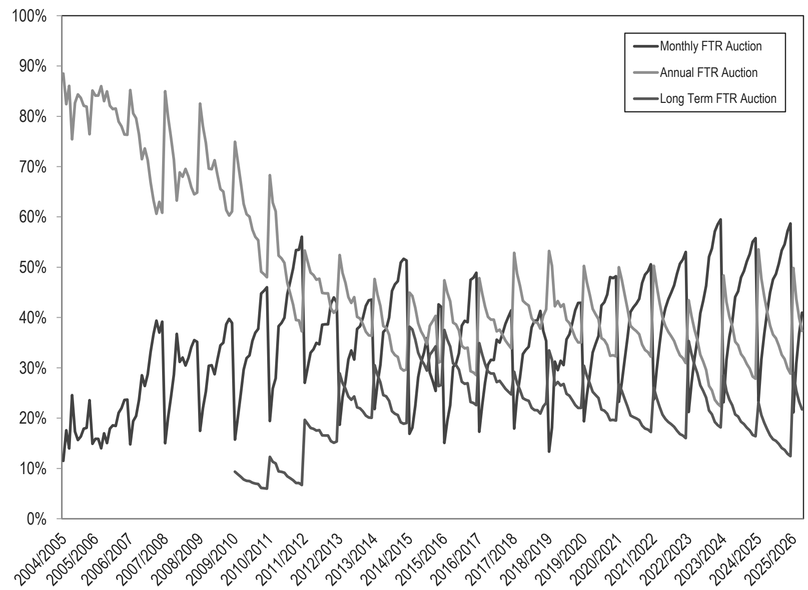


Figure 13-9 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through September 2025. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month in the relevant planning period. Over the course of each planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, resulting in a greater share of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in previous Monthly Balance of Planning Period Auctions, other than the current June auction, are no longer effective, resulting in a smaller share for monthly and a greater share for annual FTRs.

Bilateral Market

Table 13-26 provides the PJM registered secondary bilateral FTR market volume for the first four months of the 2025/2026 and the entire 2024/2025 planning periods. Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. Prior to June 30, 2024, there was no requirement to report accurate detailed information about bilateral transactions settled through PJM billing systems. Effective June 30, 2024, the Commission accepted PJM's proposed revisions to the rules that required the reporting of bilateral price information and corroborating contract documents of any bilateral change of FTR ownership between participants/accounts that is settled through

PJM settlement systems.[39] Bilateral transactions remain dependent on the contract established between the parties. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. As a result, the bilateral data are not a reliable basis for evaluating actual bilateral activity in PJM FTRs.

In the first four months of the 2025/2026 planning period there were no bilateral transactions for FTRs that were originally acquired in the 2025/2026 Auction or the Monthly Balance of Planning Period auctions. In the 2024/2025 planning period, there were eight total pairs of bilateral trading participants, three pairs of unaffiliated participants and 121 total bilateral FTR transactions.

Table 13-26 Secondary bilateral FTR market volume: 2024/2025 and 2025/2026 planning periods[40]

Planning Period	Type	Class Type	Volume (MW)
2024/2025	Obligation	24-Hour	1,196.4
		On Peak	480.4
		Daily Off Peak	127.9
		Weekend On Peak	147.8
		Total	1,952.5
	Option	24-Hour	0.0
		On Peak	0.0
		Daily Off Peak	0.0
		Weekend On Peak	0.0
		Total	0.0
2025/2026*	Obligation	24-Hour	0.0
		On Peak	0.0
		Daily Off Peak	0.0
		Weekend On Peak	0.0
		Total	0.0
	Option	24-Hour	0.0
		On Peak	0.0
		Daily Off Peak	0.0
		Weekend On Peak	0.0
		Total	0.0

*First four months of 2025/2026

39 *See* 187 FERC ¶ 61,020.
40 The 2024/2025 planning period covers bilateral FTRs that are effective for any time between June 1, 2024 through May 31, 2025, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Price

Table 13-27 shows the cleared, weighted average prices by trade type, FTR direction, period type and class type for the 2025/2028 Long Term FTR Auction. Only FTR obligation products (no options) are available in the Long Term FTR Auctions. In this auction, weighted average buy bid counter flow and prevailing flow FTR prices were -$0.82 and $0.99, compared to -$0.55 and $0.64 from the 2024/2027 Long Term FTR Auction. Weighted average sell bid counter flow and prevailing flow FTR prices were -$0.79 and $0.73, compared to -$0.66 for counter flow FTRs and $0.64 for prevailing flow FTRs for the 2024/2027 Long Term FTR Auction.

Table 13-27 Long Term FTR Auction: weighted average cleared prices (Dollars per MW): 2025/2028 auction

			Class Type				
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Counter Flow	Year 1	($2.93)	($0.36)	($0.74)	($0.60)	($0.82)
		Year 2	($2.85)	($0.43)	($0.76)	($0.62)	($0.78)
		Year 3	($3.35)	($0.53)	($0.82)	($0.65)	($0.84)
		Total	($2.99)	($0.43)	($0.77)	($0.62)	($0.82)
	Prevailing Flow	Year 1	$2.44	$0.52	$0.85	$0.71	$0.92
		Year 2	$3.21	$0.59	$0.79	$0.68	$0.97
		Year 3	$4.45	$0.69	$0.89	$0.75	$1.19
		Total	$3.10	$0.58	$0.84	$0.71	$0.99
	Total		$0.52	$0.03	$0.07	$0.05	$0.09
Sell offers	Counter Flow	Year 1	($1.07)	($0.49)	($0.90)	($0.73)	($0.75)
		Year 2	($0.88)	($0.47)	($0.97)	($0.85)	($0.79)
		Year 3	($0.63)	($0.64)	($1.33)	($0.85)	($1.03)
		Total	($0.99)	($0.50)	($0.96)	($0.78)	($0.79)
	Prevailing Flow	Year 1	$1.66	$0.53	$0.82	$0.59	$0.72
		Year 2	$1.92	$0.62	$0.73	$0.63	$0.72
		Year 3	$3.51	$0.92	$0.79	$0.70	$0.85
		Total	$1.85	$0.59	$0.79	$0.61	$0.73
	Total		$0.99	$0.20	$0.21	$0.16	$0.22

Table 13-28 shows the weighted average cleared buy bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2025/2026 planning period. The weighted average cleared buy bid price in the 2025/2026 Annual FTR Auction was $2.88 per MW, up from $1.87 per MW in the 2024/2025 Annual FTR Auction.

Table 13-28 Annual FTR Auction weighted average cleared prices (Dollars per MW): 2025/2026 planning period

			Class Type				
Trade Type	Type	FTR Direction	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Obligations	Counter Flow	($1.46)	($0.59)	($0.44)	($0.32)	($0.52)
		Prevailing Flow	$2.79	$0.93	$0.76	$0.52	$0.96
		Total	$1.62	$0.25	$0.19	$0.12	$0.29
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.56	$0.71	$0.46	$0.31	$0.53
		Total	$0.56	$0.71	$0.46	$0.31	$0.53
Self-scheduled bids	Obligations	Counter Flow	($0.24)	$0.00	$0.00	$0.00	($0.24)
		Prevailing Flow	$3.27	$1.88	$1.19	$0.69	$3.18
		Total	$3.27	$1.88	$1.19	$0.69	$3.17
Buy and self-scheduled bids	Obligations	Counter Flow	($1.46)	($0.59)	($0.44)	($0.32)	($0.52)
		Prevailing Flow	$3.06	$0.93	$0.76	$0.52	$1.19
		Total	$2.41	$0.25	$0.19	$0.12	$0.47
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.56	$0.71	$0.46	$0.31	$0.53
		Total	$0.56	$0.71	$0.46	$0.31	$0.53
Sell offers	Obligations	Counter Flow	($1.76)	($0.87)	($0.71)	($0.44)	($0.80)
		Prevailing Flow	$2.06	$0.86	$0.66	$0.55	$0.81
		Total	$0.26	$0.24	$0.16	$0.17	$0.20
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$2.02	$2.21	$1.48	$0.98	$1.68
		Total	$2.02	$2.21	$1.48	$0.98	$1.68

Table 13-29 shows the cleared buy bid volume, cleared buy bid revenue and cleared revenue/cleared MW for the last twelve planning periods. In the 2014/2015 planning period the $/MW increased significantly from the 2013/2014 planning period due to PJM's decisions to limit capacity through conservative modeling. In the 2017/2018 Annual FTR Auction, the $/MW decreased to lower than 2013/2014 levels, due in part to the partial relaxation of PJM's conservative modeling practices due to the reassignment of balancing congestion and M2M payments to load and exports. This reduction continued into the 2019/2020 planning period. Due to the more restrictive modeling for the 2022/2023 planning period (relative to the 2021/2022 planning period), quantities and revenue were similar to 2016/2017 levels, when PJM was restricting the FTR market to account for balancing congestion. The reassignment of balancing congestion and M2M payments to load did not increase the per MW value of ARRs.

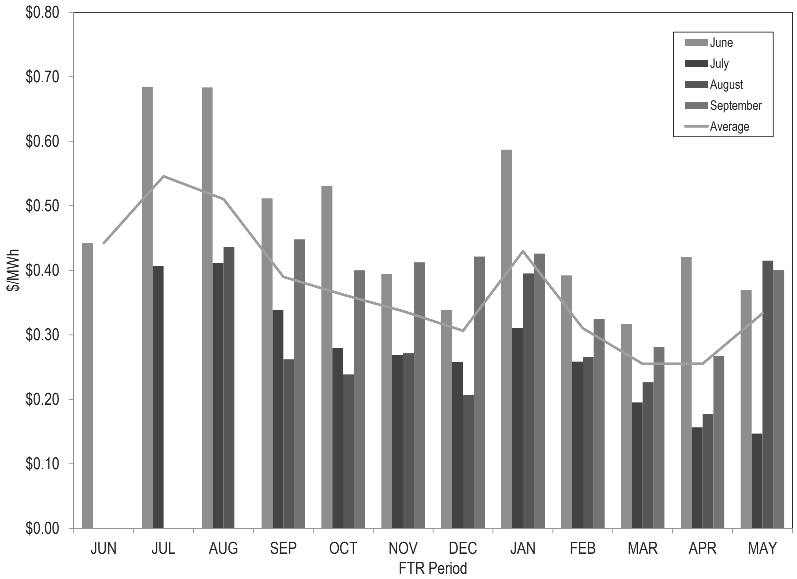
The 2023/2024 Annual FTR Auction was the first Annual FTR Auction to use the HSIM model. Following the high revenue from the 2022/2023 planning period, and the implementation of the HSIM model, the 2023/2024 Annual FTR Auction cleared buy bid volume increased by 75.9 percent. For the 2023/2024 Annual FTR Auction, the cleared buy bid volume increased 75.9 percent, total buy bid revenue decreased 12.6 percent, and buy bid revenue per MW decreased 50.1 percent. For the 2024/2025 Annual FTR Auction, cleared buy bid volume increased 17.4 percent, total buy bid revenue decreased 1.7 percent, and buy bid revenue per MW decreased 16.3 percent. In the 2025/2026 Annual FTR Auction, cleared buy bid volume increased by 29.6 percent, and buy bid revenue increased by 34.2 percent compared to the previous annual FTR auction.

Table 13-29 Cleared volume, revenue and $/MW: 2012/2013 through 2025/2026 Annual FTR Auction

	Buy Bid Volume	Cleared Buy Bid Volume	Percent Cleared	Buy Bid Revenue (millions)	Buy Bid Revenue ($/MW)
2012/2013	2,520,119	329,578	13.1%	$389.1	$1,181
2013/2014	3,245,033	391,148	12.1%	$382.5	$978
2014/2015	3,243,346	338,879	10.4%	$506.3	$1,494
2015/2016	2,437,964	354,630	14.5%	$620.5	$1,750
2016/2017	2,565,494	393,509	15.3%	$615.8	$1,565
2017/2018	2,281,534	488,734	21.4%	$406.5	$832
2018/2019	2,880,105	587,628	20.4%	$635.7	$1,082
2019/2020	2,787,716	611,878	21.9%	$649.0	$1,061
2020/2021	2,336,551	556,034	23.8%	$449.6	$809
2021/2022	2,043,408	535,277	26.2%	$519.0	$970
2022/2023	1,984,377	483,988	24.4%	$1,096.3	$2,265
2023/2024	3,746,935	851,248	22.7%	$957.9	$1,125
2024/2025	4,741,013	999,108	21.1%	$941.4	$942
2025/2026	6,628,872	1,294,688	19.5%	$1,263.6	$976

Figure 13-10 shows the weighted average cleared buy bid price of obligations in the Monthly Balance of Planning Period FTR Auctions by bidding period for the first four months of the 2025/2026 planning period and the average price per MWh for each of the FTR periods. The average price per MWh across all bidding periods for the first four months of the 2025/2026 planning period was $0.36.

Figure 13-10 Monthly Balance of Planning Period FTR Auction cleared weighted-average buy bid price per period (Dollars per MWh): 2025/2026 planning period



Profitability

FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. FTR profitability is relevant only to participants purchasing FTRs and is not relevant to self scheduled FTRs. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Profits include the payment of surplus to FTRs. Bilateral transactions are excluded from the profit calculations. Bilateral profits and losses net to zero in market total profits and losses. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned the rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Profits in the first four months of the 2025/2026 planning period include the auction cost and revenue from both buying and selling FTRs that were effective from June 2025 through September 2025. This includes FTRs from the 2023/2026, 2024/2027 and 2025/2028 Long Term auctions, the 2025/2026 Annual auction, and the Monthly auctions from June 2025 through September 2025. The costs and revenues of the yearly FTR products are prorated based on the period of the FTRs. Any revenues or costs related to bilateral transactions are not included in profits.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR. The hourly revenues equal any positive hourly FTR target allocations, adjusted by the payout ratio plus any hourly auction revenues from the sale and/or the purchase of the FTR. The hourly auction costs equal any negative hourly FTR target allocations plus any hourly auction costs from the purchase and/or the sale of the FTR. The hourly auction costs and auction revenues are the product of the FTR MW and the auction price divided by the period of the FTR in hours. The FTR revenues do not include after the fact adjustments which are very small and do not occur in every month.

The surplus includes surplus day-ahead congestion revenue and FTR auction surplus. The surplus is first allocated to FTR holders to cover any shortfall in paying FTR target allocations for the current month or prior months in the planning period. A negative surplus (shortfall) at the end of the planning period is a deficiency that is charged as FTR uplift to FTR holders. The end of planning period surplus or uplift was distributed to FTR holders prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, any surplus is given to FTR holders only up to FTR target allocations within the planning period, and, after any surplus assigned to FTRs, the net surplus at the end of the planning period is distributed to ARR holders. Profits include any surplus distribution or uplift payments that was used to satisfy any shortfall in FTR target allocations.

The fact that FTR profits in each planning period have been positive for financial entities as a group, regardless of the payout ratio, raises questions about the competitiveness of the market. FTR profits for financial entities were not positive in the 2019/2020 planning period when accounting for GreenHat losses, but were positive otherwise. FTR profits for financial entities without GreenHat losses were positive in every planning period from 2012/2013 through 2025/2026 except the 2016/2017 planning period, and were positive if summed over the entire period. Financial entities have been much more profitable than physical and physical ARR entities combined except for the 2015/2016 and the 2016/2017 planning periods (Table 13-33). It is not clear, in a competitive market, why FTRs remain persistently profitable for financial entities and much more profitable for financial entities than for other participants. In a competitive market, it is be expected that profits would be competed to zero.

Table 13-30 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction in the first four months of the 2025/2026 planning period. All physical participants who were assigned ARRs are classified as physical. Some participants that are not eligible for ARRs are classified as physical because they are physical participants, for example companies that own only generation.

In the first four months of the 2025/2026 planning period, physical participants, including physical ARR and IARR participants, received $93.0 million in profits on FTRs purchased directly (not self scheduled), up from $36.4 million profits in the same time period in the 2024/2025 planning period. Financial participants, including financial IARR participants, received $352.8 million in profits, up from $315.4 million in profits in the same time period in the 2024/2025 planning period.[41] Some IARRs owned by financial participants were self scheduled as FTRs, which lost $18,821. Self scheduled FTRs have zero cost. Physical ARR holders who self scheduled FTRs received $413.1 million in congestion revenues, up from $191.9 million in revenue in the same time period in the 2024/2025 planning period. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion and are not profits. Since the revenue from self scheduled FTRs is not profit it is excluded from the other tables in the profitability section.

41 There are financial participants who hold IARRs. The IARRs held by the financial participants were originally assigned to transmission upgrades associated with generation interconnection projects where the participant subsequently sold the associated physical assets (generation units) but kept the associated IARRs. Since these participants have not offered MW into the physical energy or capacity market and currently only hold financial positions, they are currently classified as financial participants.

Table 13-30 FTR profits and revenues by organization type and FTR direction: June through September, 2025/2026

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$330,428,744	$22,395,055	$352,823,799	($18,821)		($18,821)
Physical	$52,812,454	$2,427,098	$55,239,552			
Physical ARR	$47,419,767	($9,700,744)	$37,719,023	$412,987,270	$102,401	$413,089,670
Total	$430,660,964	$15,121,410	$445,782,374	$412,968,448	$102,401	$413,070,849

Table 13-31 compares the revenue from self scheduled FTRs and the ARR target allocation if the self scheduled FTRs were held as ARRs. Table 13-31 shows whether the self scheduled FTR holders were better off by self scheduling compared with holding ARRs. In the first four months in the 2025/2026 planning period, the total revenue returned to self scheduled FTRs was $413.1 million. If the self scheduled FTRs were held as ARRs, they would have received $251.2 million in ARR target allocation, or only 60.8 percent of the revenue received from self scheduled FTRs. One self scheduled FTR holder accounted for $336.9 million, or 81.6 percent, of the total revenue received by all self scheduled FTRs in the first four months of the 2025/2026 planning period.

Table 13-31 Self scheduled FTR revenues and unrealized ARR target allocation: June – September 2025/2026

	Self Scheduled FTRs Revenue Returned			Unrealized ARR Target Allocation		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	($18,821)		($18,821)	$85,131		$85,131
Physical						
Physical ARR	$412,987,270	$102,401	$413,089,670	$251,163,661	($33,951)	$251,129,709
Total	$412,968,448	$102,401	$413,070,849	$251,248,791	($33,951)	$251,214,840

Table 13-32 lists the monthly FTR profits for the 2024/2025 planning period and the first four months of the 2025/2026 planning period by organization type. In the first four months of the 2025/2026 planning period, profits for all participants were $445.8 million, up from $351.8 million in profits in the same time period in the 2024/2025 planning period and the highest level of profits since the 2012/2013 planning period. The increase in profits is due to the increase in FTR volume. July had the largest monthly profit in the first four months of the 2025/2026 planning period, $221.5 million. August had the smallest monthly profit, $30.4 million. The largest month to month increase in profits in the first four months of the 2025/2026 planning period was in June, an increase of $76.4 million. Among organization types, financial organizations' profits were the largest, $352.8 million, or 79.1 percent of the market's total profits. Physical ARR organizations had the largest increase in profits, $37.7 million, up from a loss of $9.9 million, although their profits were the smallest among organization types.

Table 13-32 Monthly FTR profits by organization type: 2024/2025 through September 2025/2026

	Organization Type			
Month	Financial	Physical	Physical ARR	Total
Jun-24	$47,118,337	($625,023)	($6,496,086)	$39,997,228
Jul-24	$140,890,180	$26,747,762	$3,673,731	$171,311,673
Aug-24	$89,115,812	$14,471,496	($3,597,813)	$99,989,494
Sep-24	$38,225,761	$5,734,554	($3,506,030)	$40,454,285
Oct-24	$34,019,402	$4,437,290	$4,457,735	$42,914,427
Nov-24	$4,454,325	($4,204,643)	($11,749,666)	($11,499,985)
Dec-24	$94,290,172	$23,591,538	($119,565)	$117,762,146
Jan-25	$135,793,868	$4,793,121	($10,788,364)	$129,798,624
Feb-25	$46,755,828	$12,458,346	($17,964,016)	$41,250,157
Mar-25	$114,057,458	$6,111,111	$6,838,610	$127,007,179
Apr-25	$60,134,385	($3,340,649)	$2,667,505	$59,461,242
May-25	$49,921,607	($5,061,517)	($5,977,119)	$38,882,971
Summary for Planning Period 2024/2025				
Total	$854,777,135	$85,113,384	($42,561,078)	$897,329,441
Jun-25	$92,206,975	$10,730,035	$13,494,064	$116,431,074
Jul-25	$165,773,391	$29,775,894	$25,986,128	$221,535,414
Aug-25	$45,813,799	$6,474,427	($21,925,617)	$30,362,609
Sep-25	$49,029,634	$8,259,195	$20,164,447	$77,453,277
Summary for Planning Period 2025/2026				
Total	$352,823,799	$55,239,552	$37,719,023	$445,782,374

Table 13-33 lists the historical profits by planning period by organization type beginning in the 2012/2013 planning period for purchased FTRs. (Profits do not include congestion revenue to self scheduled FTRs.) The rules governing the allocation of surplus are described later in this section.

Table 13-33 FTR profits by organization type: 2012/2013 through 2025/2026

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
Financial	Profit	$201,825,234	$913,502,323	$250,551,943	$68,895,867	($12,525,947)	$239,981,474	$113,086,231	($21,139,644)	$280,586,579	$831,489,515	$376,720,527	$227,123,570	$854,777,135	$352,823,799
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918								
	Total	$151,520,826	$768,421,802	$270,005,781	$73,816,945	($3,715,680)	$330,343,392	$113,086,231	($21,139,644)	$280,586,579	$831,489,515	$376,720,527	$227,123,570	$854,777,135	$352,823,799
Financial without GreenHat	Profit	$201,825,234	$913,502,323	$250,551,785	$70,094,918	($11,821,248)	$240,111,850	$223,376,757	$25,150,852	$280,906,014	$831,489,515	$376,720,527	$227,123,570	$854,777,135	$352,823,799
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918								
	Total	$151,520,826	$768,421,802	$270,005,623	$75,015,995	($3,010,981)	$330,473,768	$223,376,757	$25,150,852	$280,906,014	$831,489,515	$376,720,527	$227,123,570	$854,777,135	$352,823,799
Physical	Profit	$68,537,800	$297,456,284	$82,853,390	$10,007,327	($4,010,669)	$57,532,872	($5,945,233)	($42,860,656)	$60,941,495	$228,289,196	$10,155,622	$3,268,080	$85,113,384	$55,239,552
	Surplus	($41,626,011)	($53,642,077)	$5,395,706	$1,865,146	$4,181,855	$34,296,618								
	Total	$26,911,789	$243,814,207	$88,249,096	$11,872,473	$171,186	$91,829,490	($5,945,233)	($42,860,656)	$60,941,495	$228,289,196	$10,155,622	$3,268,080	$85,113,384	$55,239,552
Physical ARR	Profit	$26,572,818	$366,128,947	$112,609,140	$82,181,795	($2,468,152)	$66,458,939	($6,248,557)	($49,614,191)	$18,982,052	$35,163,444	($14,794,445)	$12,419,666	($42,561,078)	$37,719,023
	Surplus	($25,873,836)	($81,279,067)	$18,515,990	$7,110,576	$12,040,688	$47,753,635								
	Surplus from Self scheduled FTRs	($45,978,766)	($81,765,964)	$15,530,158	$3,073,711	$6,469,297	$42,513,186								
	Total	$698,982	$284,849,881	$131,125,130	$89,292,371	$9,572,536	$114,212,574	($6,248,557)	($49,614,191)	$18,982,052	$35,163,444	($14,794,445)	$12,419,666	($42,561,078)	$37,719,023
Total		$179,131,597	$1,297,085,890	$489,380,007	$174,981,788	$6,028,043	$536,385,456	$100,892,442	($113,614,490)	$360,510,126	$1,094,942,155	$372,081,704	$242,811,317	$897,329,441	$445,782,374

* The first four months of the 2025/2026 planning period

Table 13-34 shows the profits and losses of the five most and the five least profitable participants by ownership type. Total MWh is the sum of all MWh by ownership type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by ownership type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top 5 participants by ownership type. The Top 5 Market Share of MWh is the sum of the MWh of the top 5 participants by ownership type divided by Total MWh of that ownership type. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by ownership type. The same logic applies for the statistics related to the Bottom 5 participants. The All row considers all ownership types when selecting the Top 5 and Bottom 5 participants.

The sum of the Top 5 financial participants' profits was the largest of all the ownership types, $142.6 million, while the sum of the Top 5 physical ARR participants' profits (excluding self-scheduled FTRS) was the smallest, $47.9 million. While having the smallest sum of profits, the Top 5 physical ARR's sum of profit increased the most by $39.0 million, or 437.7 percent increase. Each of the ownership type's top 5 profit increased in the first four months of the 2025/2026 planning period compared with the same time period in the 2024/2025 planning period. The Bottom 5 financial participants' sum of losses was the largest while their loss per MWh was the smallest. Only the Bottom 5 physical ARR participants' sum of losses decreased in the first four months of the 2025/2026 planning period compared with the same time period in the 2024/2025 planning period. When all participants across ownership types are considered, three of the Top 5 participants and three of the bottom 5 participants were financial participants. Overall, the five most profitable participants' profits and profits per MWh increased and the five least profitable participants' losses and losses per MWh decreased in the first four months of the 2025/2026 planning period compared with the same time period in the 2024/2025 planning period.

There are participants who have had persistent losses for multiple years. It is possible for PJM FTR participants to have complementary positions in other trading platforms such as the Intercontinental Exchange (ICE) or Nodal Exchange or in other products in the PJM market.

Table 13-34 Top 5 and bottom 5 FTR profits by ownership type: June through September, 2025/2026

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	1,952,886,625	$142,646,228	$0.56	13.2%	38.3%	($10,227,620)	($0.05)	9.9%	51.2%
Physical	61,364,232	$56,436,089	$1.61	57.1%	92.4%	($5,129,464)	($1.22)	6.8%	88.0%
Physical ARR	108,475,404	$47,936,960	$0.69	64.0%	96.3%	($7,028,377)	($0.27)	23.6%	58.4%
All	2,122,726,261	$170,150,104	$0.70	11.4%	35.2%	($12,231,326)	($0.08)	7.0%	32.3%

Table 13-35 shows the shares of profitable and unprofitable participants by ownership type weighted by FTR MW in the first four months of the 2025/2026 planning period. There were more profitable participants than unprofitable participants for each organization type and for market total. Compared with the same time period in the 2024/2025 planning period, in the first four months of the 2025/2026 planning period, the share of profitable participants decreased by 8.7 percentage points from 89.6 percent to 80.8 percent. Physical ARR organizations were the only organization type whose share of profitable participants increased.

Table 13-35 Share of participants MWh by profitability by ownership type: June through September, 2025/2026

Organization Type	Unprofitable	Profitable
Financial	18.6%	81.4%
Physical	21.1%	78.9%
Physical ARR	28.6%	71.4%
Total	19.2%	80.8%

Table 13-36 shows the profits by source and sink node type in the first four months of the 2025/2026 planning period. The sink total row is the sum of all profits and losses of FTRs that have the same sink node type. The source total column is the sum of all profits and losses of FTRs that have the same source node type. The profits of generator to generator FTRs were the largest, $108.6 million in the first four months of the 2025/2026 planning period. However, the profits of generator to generator FTRs had the largest decrease in profits ($43.6 million decrease) compared with the same time period in the 2024/2025 planning period. The losses of hub to hub FTRs were the largest, a loss of $19.7 million, in the first four months of the 2025/2026 planning period.

Table 13-36 Profits by node type matrix: June through September, 2025/2026

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	$4,931,733	$182,177	($2,411,031)	$1,123,779	($157,564)	($121,894)	$2,549,005	$4,360,733	$10,456,936
EHVAGG	$47,927	$1,644,597	($436,236)	$9,322	$23,426	$3,887,942	$16,054	$4,263	$5,197,295
Generator	$50,330,799	$1,907,660	$108,551,296	$73,891,483	$7,009,275	$23,317,054	$37,158,448	$91,111,383	$393,277,397
Hub	($2,705,857)	$598,608	($1,081,578)	($19,707,159)	$1,486,603	$167,031	$7,307,934	$4,998,347	($8,936,071)
Interface	($490,932)	($38,399)	($7,132,491)	($158,075)	$59,072	$1,072,172	($130,562)	($1,533,509)	($8,352,725)
Load	$10,842	($2,143,041)	($3,099,611)	$247,019	$178,384	$22,980,445	$109,337	$104,641	$18,388,014
Residual Metered Aggregate	($303,152)	$3,678	($7,385,482)	($23,674)	$328,323	($321,089)	$851,591	$405,882	($6,443,923)
Zone	($365,842)	$440	($12,218,317)	$24,688,957	$19,965,895	$73,723	$1,352,918	$8,697,677	$42,195,450
Sink Total	$51,455,518	$2,155,719	$74,786,549	$80,071,652	$28,893,412	$51,055,384	$49,214,724	$108,149,416	$445,782,374

Table 13-37 shows the profit per MWh by source and sink node type in the first four months of the 2025/2026 planning period. The sink total row represents the average profit per MWh of FTRs that have the same sink type. The source total column shows the average profit per MWh of FTRs that have the same source type. Interface to load FTRs had the highest profit per MWh, $11.30 per MWh. Interface to zone FTRs had the largest loss per MWh, -$2.37 per MWh. Profit per MWh of generator to generator FTRs was $0.11 per MWh, below the market average of $0.21 per MWh.

Table 13-37 Profit per MWh by node type matrix: June through September, 2025/2026

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	$0.20	$0.84	($0.02)	$0.44	($0.10)	($0.03)	$0.37	$0.53	$0.07
EHVAGG	$0.17	$0.42	($0.18)	$0.23	$2.02	$0.75	$0.24	$0.04	$0.43
Generator	$0.33	$0.61	$0.11	$1.32	$0.43	$0.50	$1.36	$0.87	$0.27
Hub	($0.40)	$8.20	($0.10)	($0.82)	$1.51	$0.67	$0.83	$0.07	($0.08)
Interface	($0.76)	($1.41)	($1.21)	($0.24)	$0.40	$11.30	($0.42)	($2.37)	($0.99)
Load	$0.00	($0.74)	($0.09)	$0.53	$0.60	$0.12	$0.16	$0.25	$0.08
Residual Metered Aggregate	($0.06)	$0.22	($0.39)	($0.02)	$1.13	($0.42)	$0.72	$0.12	($0.21)
Zone	($0.04)	$0.07	($0.52)	$0.97	$3.74	$0.12	$0.08	$0.23	$0.36
Sink Total	$0.26	$0.21	$0.06	$0.73	$1.16	$0.20	$0.78	$0.49	$0.21

Revenue

Long Term FTR Auction Revenue

Table 13-38 shows the Long Term FTR Auction revenue data by trade type, FTR direction, period type and class type. The 2025/2028 Long Term FTR Auction netted $162,279,258 million in revenue, $59,642,543 million less (58.1 percent) than the previous Long Term FTR Auction. Buyers paid $276,421,108 million, up $86.7 million (45.7 percent), and sellers received $114,141,850 million, up $27.1 million (31.1 percent) over the previous Long Term FTR Auction.

Table 13-38 Long Term FTR Auction Revenue: 2025/2028 auction

			Class Type				
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Counter Flow	Year 1	($187,909,984)	($216,963,118)	($64,608,262)	($67,215,408)	($536,696,773)
		Year 2	($80,728,121)	($146,341,601)	($44,179,335)	($53,862,609)	($325,111,666)
		Year 3	($70,360,632)	($159,733,337)	($43,905,537)	($60,395,562)	($334,395,068)
		Total	($338,998,737)	($523,038,056)	($152,693,134)	($181,473,579)	($1,196,203,506)
	Prevailing Flow	Year 1	$184,712,464	$298,658,914	$88,488,683	$89,254,850	$661,114,911
		Year 2	$142,914,374	$168,975,183	$49,503,854	$59,268,382	$420,661,792
		Year 3	$150,371,570	$148,848,595	$38,892,667	$52,735,079	$390,847,911
		Total	$477,998,407	$616,482,692	$176,885,204	$201,258,311	$1,472,624,614
	Total		$138,999,670	$93,444,636	$24,192,070	$19,784,732	$276,421,108
Sell offers	Counter Flow	Year 1	($2,959,644)	($50,360,324)	($13,442,689)	($16,488,436)	($83,251,094)
		Year 2	($1,189,086)	($23,147,648)	($7,132,432)	($7,127,277)	($38,596,441)
		Year 3	($113,923)	($10,445,499)	($2,492,898)	($2,851,597)	($15,903,917)
		Total	($4,262,653)	($83,953,471)	($23,068,019)	($26,467,309)	($137,751,452)
	Prevailing Flow	Year 1	$8,788,063	$85,144,620	$21,508,078	$28,247,333	$143,688,093
		Year 2	$8,128,977	$44,380,646	$12,867,821	$20,932,602	$86,310,046
		Year 3	$1,369,541	$10,544,270	$3,079,649	$6,901,703	$21,895,163
		Total	$18,286,581	$140,069,535	$37,455,548	$56,081,638	$251,893,302
	Total		$14,023,929	$56,116,064	$14,387,529	$29,614,328	$114,141,850
Total			$124,975,741	$37,328,572	$9,804,541	($9,829,596)	$162,279,258

Annual FTR Auction Revenue

Table 13-39 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2025/2026 planning period generated $1,895.3 million, up 28.5 percent from $1,475.3 million in the 2024/2025 Annual FTR Auction. Counter flow FTR holders received $701.0 million, up 116.8 percent from the previous Annual FTR Auction and prevailing flow FTR holders paid $2,596.4 million, up 44.4 percent from the previous planning period.

Table 13-39 Annual FTR auction revenue: 2025/2026 planning period

			Class Type				
Trade Type	Type	FTR Direction	24-Hour	On Peak	Weekend On Peak	Daily Off Peak	All
Buy bids	Obligations	Counter Flow	($99,152,385)	($481,420,630)	($136,052,349)	($156,244,140)	($872,869,504)
		Prevailing Flow	$498,216,463	$933,963,451	$261,323,797	$274,545,181	$1,968,048,892
		Total	$399,064,078	$452,542,820	$125,271,448	$118,301,041	$1,095,179,388
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$16,561,879	$90,735,513	$29,938,410	$31,215,684	$168,451,486
		Total	$16,561,879	$90,735,513	$29,938,410	$31,215,684	$168,451,486
	Total	Counter Flow	($99,152,385)	($481,420,630)	($136,052,349)	($156,244,140)	($872,869,504)
		Prevailing Flow	$514,778,342	$1,024,698,964	$291,262,207	$305,760,865	$2,136,500,378
		Total	$415,625,957	$543,278,334	$155,209,858	$149,516,725	$1,263,630,873
Self-scheduled bids	Obligations	Counter Flow	($101,575)	$0	$0	$0	($101,575)
		Prevailing Flow	$735,751,303	$10,786,097	$2,660,019	$2,483,928	$751,681,346
		Total	$735,649,727	$10,786,097	$2,660,019	$2,483,928	$751,579,771
Buy and self-scheduled bids	Obligations	Counter Flow	($99,253,960)	($481,420,630)	($136,052,349)	($156,244,140)	($872,971,080)
		Prevailing Flow	$1,233,967,766	$944,749,547	$263,983,816	$277,029,109	$2,719,730,238
		Total	$1,134,713,806	$463,328,917	$127,931,467	$120,784,969	$1,846,759,158
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$16,561,879	$90,735,513	$29,938,410	$31,215,684	$168,451,486
		Total	$16,561,879	$90,735,513	$29,938,410	$31,215,684	$168,451,486
	Total	Counter Flow	($99,253,960)	($481,420,630)	($136,052,349)	($156,244,140)	($872,971,080)
		Prevailing Flow	$1,250,529,644	$1,035,485,060	$293,922,226	$308,244,793	$2,888,181,724
		Total	$1,151,275,684	$554,064,430	$157,869,877	$152,000,653	$2,015,210,644
Sell offers	Obligations	Counter Flow	($33,651,501)	($84,515,741)	($26,247,005)	($27,513,050)	($171,927,297)
		Prevailing Flow	$44,057,528	$148,292,408	$42,217,276	$53,983,613	$288,550,825
		Total	$10,406,026	$63,776,667	$15,970,271	$26,470,563	$116,623,528
	Options	Counter Flow	$0	$0	$0	$0	$0
		Prevailing Flow	$430,953	$1,591,432	$731,895	$515,750	$3,270,030
		Total	$430,953	$1,591,432	$731,895	$515,750	$3,270,030
	Total	Counter Flow	($33,651,501)	($84,515,741)	($26,247,005)	($27,513,050)	($171,927,297)
		Prevailing Flow	$44,488,481	$149,883,840	$42,949,171	$54,499,363	$291,820,855
		Total	$10,836,979	$65,368,099	$16,702,166	$26,986,313	$119,893,558
Total			$1,140,438,705	$488,696,331	$141,167,711	$125,014,340	$1,895,317,086

FTRs sold in Long Term FTR Auctions are sold at a substantial discount to the same FTRs sold in Annual FTR Auctions. Table 13-40 shows the increase in total auction revenue that would have resulted for the 2014/2015 through 2025/2026 planning periods if long term FTRs were sold at annual auction clearing prices.

Long Term FTR Auction MW are determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction. But even this approach does not, and cannot, preserve all the capacity for ARR holders in the first year of the Long Term Auction. The MW purchased in the Long Term FTR Auction are made available to FTR holders before ARR holders have access to them. The result is that MW are reserved, inappropriately and for unexplained reasons, in future auctions for FTR holders. This difference provides an estimate of the value of the MW made available in the Long Term FTR Auction that are not made available to ARR holders. These MW should be made available to ARR holders in the Annual FTR Auctions where they are the most valuable. Under the current market rules, MW made available in the Long Term FTR auction are not available to ARR holders as ARRs. The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market, and not projected residual system capability based on a snapshot of prior ARR requests.

Table 13-40 Estimated additional Long Term FTR Auction revenue at Annual FTR Auction prices

	Long Term FTR Product				
Planning Period	YR3	YR2	YR1	YRALL	Total Difference
2014/2015	$59,598,642	$30,284,173	$52,030,909	$926,989	$142,840,713
2015/2016	$67,896,588	$40,975,278	$9,936,078	$303,082	$119,111,026
2016/2017	$42,378,048	$3,854,373	$11,055,824	$1,079,901	$58,368,147
2017/2018	$6,134,076	($1,841,715)	$12,396,817	$227,524	$16,916,702
2018/2019	$7,872,604	$2,926,457	$13,480,353	($111,226)	$24,168,189
2019/2020	$9,711,188	$4,098,887	$103,227,004	$805,425	$117,842,504
2020/2021	($416,585)	$52,736,819	($9,690,808)	$1,242,707	$43,872,132
2021/2022	$73,050,796	($3,111,721)	$13,856,264	NA	$83,795,339
2022/2023	$42,759,622	$62,664,762	$104,025,268	NA	$209,449,652
2023/2024	$45,464,085	$31,335,632	$39,140,382	NA	$115,940,099
2024/2025	$42,500,160	$23,979,155	$36,720,756	NA	$103,200,071
2025/2026	$100,410,553	$68,518,553	$93,705,408	NA	$262,634,514
Total	$497,359,776	$316,420,654	$479,884,255	$4,474,401	$1,298,139,087

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-41 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for the first four months of the 2025/2026 and the entire 2024/2025 planning periods. The Monthly Balance of Planning Period FTR Auctions for the first four months of the 2025/2026 planning period netted $39.9 million in revenue, the difference between buyers paying $448.4 million and sellers receiving $408.6 million. For the entire 2024/2025 planning period, the Monthly Balance of Planning Period FTR Auctions netted $79.6 million in revenue with buyers paying $671.2 million and sellers receiving $591.6 million. Revenue from obligation buy bids for the first four months of the 2025/2026 planning period was 18.0 percent compared to the same period of the 2024/2025 planning period. Revenue from obligation sell offers in the first four months of the 2025/2026 planning period was up 13.4 percent compared to the same period of the 2024/2025 planning period.

Table 13-41 Monthly Balance of Planning Period FTR Auction revenue: 2024/2025 and 2025/2026 planning period

			Class Type				
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Daily Off Peak	Weekend On Peak	All
Jun-25	Obligations	Buy bids	$43,963,789	$59,550,615	$11,244,539	$17,818,883	$132,577,826
		Sell offers	$10,807,119	$53,694,995	$13,744,740	$17,282,983	$95,529,837
	Options	Buy bids	$232,202	$8,861,467	$4,007,673	$2,867,090	$15,968,432
		Sell offers	$2,969,446	$21,150,179	$5,658,918	$6,780,519	$36,559,061
Jul-25	Obligations	Buy bids	$11,769,736	$47,782,060	$10,707,639	$14,767,032	$85,026,467
		Sell offers	$3,763,947	$38,944,621	$8,273,644	$11,761,740	$62,743,951
	Options	Buy bids	$2,132,213	$7,568,007	$3,473,035	$2,743,547	$15,916,801
		Sell offers	$2,703,871	$19,837,413	$4,823,689	$6,517,948	$33,882,921
Aug-25	Obligations	Buy bids	($346,749)	$50,008,965	$12,464,614	$16,378,232	$78,505,063
		Sell offers	$2,897,894	$31,862,957	$7,672,652	$11,359,638	$53,793,141
	Options	Buy bids	$534,023	$7,479,258	$3,559,637	$2,734,285	$14,307,204
		Sell offers	$2,638,486	$16,477,506	$4,647,661	$5,396,476	$29,160,129
Sep-25	Obligations	Buy bids	($3,169,946)	$54,069,302	$21,118,313	$17,242,156	$89,259,824
		Sell offers	$21,189,710	$31,183,579	$9,973,679	$9,419,961	$71,766,929
	Options	Buy bids	$834,043	$8,840,903	$3,789,646	$3,408,415	$16,873,008
		Sell offers	$2,077,559	$13,173,571	$5,452,261	$4,425,345	$25,128,736
2024/2025*	Obligations	Buy bids	$92,291,775	$334,508,875	$87,723,212	$82,618,475	$597,142,337
		Sell offers	$24,741,555	$270,347,683	$73,133,231	$67,754,244	$435,976,713
	Options	Buy bids	$16,363,731	$31,182,988	$14,530,149	$11,936,121	$74,012,989
		Sell offers	$19,034,193	$80,149,449	$30,035,406	$26,381,757	$155,600,805
	Net Total		$64,879,758	$15,194,731	($915,277)	$418,596	$79,577,808
2025/2026**	Obligations	Buy bids	$52,216,829	$211,410,942	$55,535,106	$66,206,303	$385,369,180
		Sell offers	$38,658,669	$155,686,152	$39,664,715	$49,824,322	$283,833,858
	Options	Buy bids	$3,732,481	$32,749,635	$14,829,992	$11,753,337	$63,065,445
		Sell offers	$10,389,362	$70,638,668	$20,582,528	$23,120,289	$124,730,848
	Net Total		$6,901,279	$17,835,757	$10,117,855	$5,015,029	$39,869,919

*Shows twelve months for 2024/2025 **Shows four months for 2025/2026

Table 13-42 shows the monthly balance of planning period FTR auction revenue by FTR direction and trade type for FTRs effective in each month. For example, June 2025 shows FTR auction revenue for FTRs that are effective in June that were sold in the June 2025 Auction. July 2025 shows FTR auction revenue for FTRs that are effective in July that were sold in the June 2025 Auction and the July 2025 Auction. Table 13-42 also shows the monthly Residual ARR target allocations. Residual ARR target allocations in a month should be fully funded by FTR auction revenue from FTRs that are effective in the same month.

Auction revenue from monthly FTRs effective in the first four months of the 2025/2026 plannning period was $18,138,911, down 5.0 percent from $19,102,401 in the same period of the 2024/2025 planning period. However, Residual ARR target allocations in the first four months of the 2025/2026 planinng period were $50,533,920, up 819.9 percent from $5,493,683 in the same period of the 2024/2025 planning period.

While total auction revenue from monthly FTRs effective in the first four months of the 2025/2026 planning period was down 5.0 percent, the results by FTR direction (prevailing versus counterflow) and by trade type (buy versus sell) were different. Negative auction revenue from buy bids for counter flow FTRs effective in the first four months of the 2025/2026 planning period was $241,552,054, up 95.5 percent from $123,550,174 in the same period of the 2024/2025 planing period. Positive auction revenue from sell bids for counter flow FTRs effective in the first four months of the 2025/2026 planning period was $92,257,662, up 73.1 percent from $53,298,619 in the same period of the 2024/2025 planning period. Positive auction revenue from buy bids for prevailing flow FTRs effective in the first four months of the 2025/2026 planning period was $437,190,572, up 58.2 percent from $276,368,421 in the same period of the 2024/2025 planning period. Negative auction revenue from sell bids for prevailing flow FTRs effective in the first four months of the 2025/2026 planning period was $269,757,269, up 44.2 percent from $187,014,465 in the same period of the 2024/2025 planning period. The disproportionate increase in negative auction revenue from counter flow FTRs effective in the first four months of the planning period contributed to the first ARR deficiency in the history of the ARR market in July 2025 (See Table 13-10). If PJM had sold fewer counter flow FTRs effective in July 2025, there would not have been an ARR deficiency.

Table 13-42 Monthly Balance of Planning Period FTR Auction revenue by FTR period compared to Residual ARR target allocations: 2024/2025 and 2025/2026

	Revenue From Monthly FTR Auctions By Period					
Month	Counter Flow Buy Bids	Counter Flow Sell Bids	Prevailing Flow Buy Bids	Prevailing Flow Sell Bids	All	Residual ARR Target Allocations
Jun-24	($12,935,096)	$6,463,400	$30,668,516	($21,035,151)	$3,161,668	$1,542,269
Jul-24	($27,907,987)	$12,672,303	$62,067,006	($42,200,251)	$4,631,071	$817,746
Aug-24	($35,671,626)	$17,132,476	$88,169,309	($63,820,383)	$5,809,776	$2,192,686
Sep-24	($47,035,465)	$17,030,440	$95,463,590	($59,958,680)	$5,499,885	$940,983
Oct-24	($61,463,190)	$22,257,984	$113,529,086	($66,887,221)	$7,436,660	$675,276
Nov-24	($57,049,350)	$21,841,656	$110,922,641	($68,430,428)	$7,284,518	$389,592
Dec-24	($73,445,957)	$24,806,231	$127,502,478	($71,230,090)	$7,632,662	$1,423,964
Jan-25	($96,757,094)	$33,228,566	$172,405,984	($101,741,615)	$7,135,841	$3,351,831
Feb-25	($94,081,134)	$32,261,091	$164,140,690	($95,141,385)	$7,179,262	$9,503,030
Mar-25	($79,877,699)	$27,581,488	$141,629,663	($82,498,441)	$6,835,012	$1,258,883
Apr-25	($88,162,518)	$29,973,301	$158,981,445	($92,626,958)	$8,165,270	$3,845,490
May-25	($99,848,832)	$31,544,129	$179,910,865	($102,799,980)	$8,806,182	$367,497
	Summary For Planning Period 2024/2025					
Total	($774,235,947)	$276,793,065	$1,445,391,273	($868,370,583)	$79,577,808	$26,309,246
Jun-25	($25,629,760)	$11,335,282	$51,618,952	($35,385,606)	$1,938,869	$12,903,832
Jul-25	($61,853,731)	$22,288,524	$111,168,475	($66,648,525)	$4,954,744	$23,175,461
Aug-25	($73,536,354)	$29,025,252	$133,268,414	($83,203,970)	$5,553,342	$13,502,528
Sep-25	($80,532,210)	$29,608,604	$141,134,731	($84,519,169)	$5,691,956	$952,098
	Summary For Planning Period 2025/2026*					
Total	($241,552,054)	$92,257,662	$437,190,572	($269,757,269)	$18,138,911	$50,533,920

*First four months of the 2025/2026 planning period

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-11 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first four months of the 2025/2026 planning period. The top 10 sinks that produced financial benefit accounted for 24.2 percent of total positive target allocations with the Dominion Residual Aggregate accounting for 8.8 percent of all positive target allocations. The top 10 sinks that created liability accounted for 9.8 percent of total negative target allocations with PPL accounting for 1.7 percent of all negative target allocations.

Figure 13-11 Ten largest positive and negative FTR target allocations summed by sink: June through September, 2025/2026

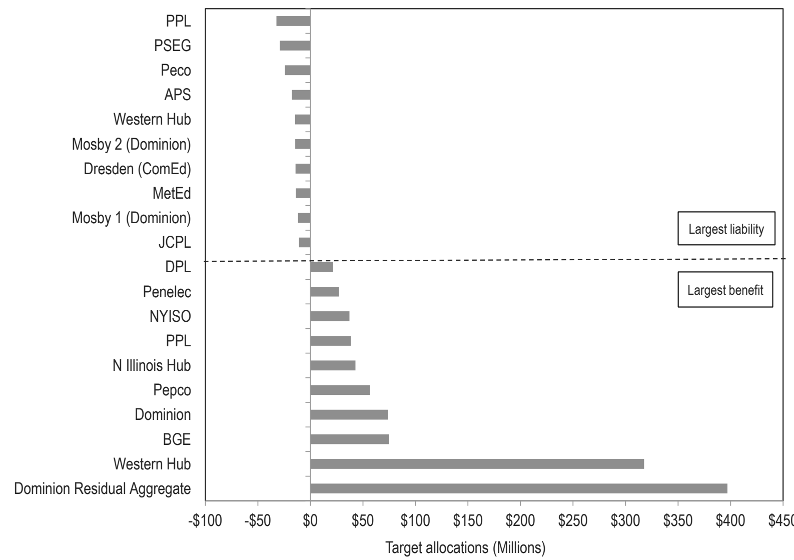
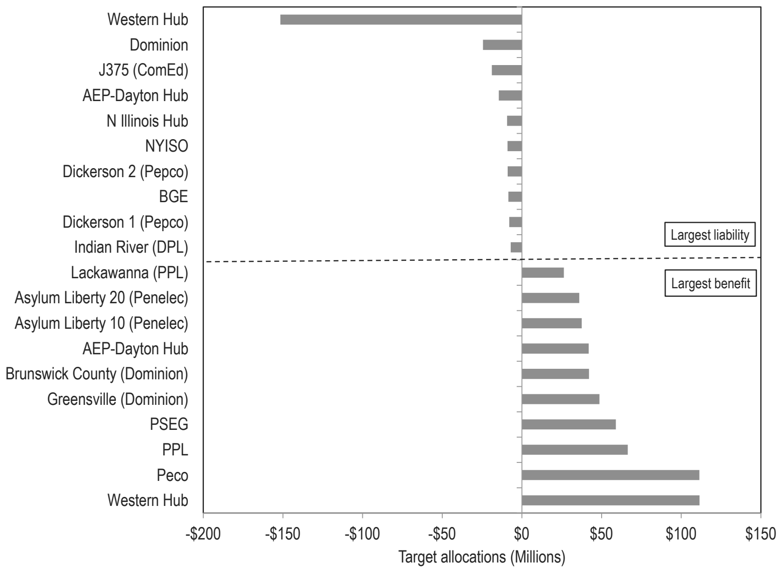


Figure 13-12 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first four months of the 2025/2026 planning period. The top 10 sources with a positive target allocation accounted for 12.9 percent of total positive target allocations with Western Hub accounting for 2.5 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 13.9 percent of all negative target allocations, with the Western Hub accounting for 8.1 percent of total negative target allocations.

Figure 13-12 Ten largest positive and negative FTR target allocations summed by source: June through September, 2025/2026



The Effect of Fast Start Pricing on FTR Target Allocations

PJM implemented fast start pricing on September 1, 2021, and as a result, PJM produces separate dispatch and pricing market solutions. The dispatch run results in dispatch instructions and matching prices, termed dispatch run locational marginal prices, or DLMP. The DLMP prices are the prices that would have been the LMPs prior to fast start pricing. The pricing run results in the final prices used in settlements and for FTR target allocations, termed pricing run locational marginal prices, or PLMP. The two runs result in different sets of target allocations for the same FTR paths. Table 13-43 compares the target allocations that result from the pricing and dispatch runs for both self scheduled and all other FTRs for the 2021/2022 planning period through the first four months of the 2025/2026 planning period. The difference indicates whether the target allocations were increased or decreased as a result of fast start pricing.

Table 13-43 Pricing run and dispatch run FTR Target Allocations: 2021/2022 through 2025/2026 planning periods

Planning Period		Pricing Run	Dispatch Run	Difference	Percent Difference
2021/2022*	Not Self Scheduled	$1,499,077,738	$1,497,963,895	$1,113,844	0.1%
	Self Scheduled	$429,271,338	$430,800,598	($1,529,260)	(0.4%)
	Total	$1,928,349,076	$1,928,764,493	($415,416)	(0.0%)
2022/2023	Not Self Scheduled	$1,641,324,421	$1,586,284,502	$55,039,919	3.4%
	Self Scheduled	$622,535,802	$668,468,552	($45,932,751)	(7.4%)
	Total	$2,263,860,223	$2,254,753,054	$9,107,169	0.4%
2023/2024	Not Self Scheduled	$1,396,273,015	$1,435,733,398	($39,460,383)	(2.8%)
	Self Scheduled	$371,433,164	$371,620,633	($187,469)	(0.1%)
	Total	$1,767,706,179	$1,807,354,031	($39,647,853)	(2.2%)
2024/2025	Not Self Scheduled	$2,077,018,180	$2,088,851,413	($11,833,233)	(0.6%)
	Self Scheduled	$657,847,842	$660,668,360	($2,820,518)	(0.4%)
	Total	$2,734,866,022	$2,749,519,773	($14,653,751)	(0.5%)
2025/2026**	Not Self Scheduled	$897,404,758	$894,207,335	$3,197,423	0.4%
	Self Scheduled	$413,068,594	$660,668,360	($247,599,766)	(59.9%)
	Total	$1,310,473,353	$1,554,875,695	($244,402,343)	(18.6%)

* starting in September 2021
** first four months of the 2025/2026 planning period

Surplus Congestion Revenue

Surplus congestion revenue is a misnomer. There is no such thing as surplus congestion revenue. The rights to all congestion revenue belong to load. Surplus congestion revenue, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs. In the current design, surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues.

Based on market logic, there is no such thing as surplus FTR auction revenue. FTR Auction revenue results from the market prices paid by willing FTR buyers, should be paid to ARR holders who are the sellers, and should not be returned to FTR buyers for any reason.

Under the existing PJM rules, surplus day-ahead congestion is defined as the difference between the day-ahead congestion paid and FTR target allocations. Under the existing PJM rules, surplus FTR auction revenue is defined as the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and from FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Under the existing PJM rules, surplus congestion revenue is defined as the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month.[42] Beginning with the 2014/2015 planning period, PJM may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.[43] The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any negative difference between day-ahead congestion revenue and FTR target allocations for the current month or prior months in the planning period. Any remaining surplus is used to pay any negative difference between day-ahead congestion revenue and FTR target allocations for the entire planning period at the end of the planning period. Any remaining surplus after that is distributed to ARR holders.[44]

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Figure 13-13 shows the monthly composition of total surplus, by surplus FTR auction revenue and surplus congestion revenue from June 2017 through September 2025 as if FTRs were settled monthly, based on the congestion and FTR auction revenue in each individual month. In only two of the first four months of the 2025/2026 planning period (June and July) the day ahead congestion in that month alone was enough to pay FTR target allocations for the month. In July 2025 there was no auction surplus and ARR holders were not paid the full target allocations for the month. Months with ARR deficiencies will be funded at the end of the planning period from surplus FTR revenues if there is an FTR surplus or through an uplift charge to FTR holders if there is not an FTR surplus. Figure 13-13 shows the extent to which FTRs are funded by the auction surplus. As part of the illogic of the FTR/ARR construct and as an illustration that it is unlike any actual market, FTR buyers pay ARR holders for the rights to congestion but FTR buyers may reclaim part of their payment if actual congestion is less than they expected and not enough to cover target allocations.

The market rules should recognize that ARR holders have the right to all surplus FTR auction revenue, not just the remainder after guaranteeing that FTRs are paid target allocations. The surplus FTR auction revenue results from the prices that FTR buyers willingly paid for the rights to price differences across specific paths. The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. The MMU recommends that, under the current FTR design, all congestion revenue

42 Prior to the 2017/2018 planning period, the surplus congestion revenue was not the simple sum of the surplus FTR auction revenue and surplus day-ahead congestion because there were various cross market charges subtracted from FTR revenue, including M2M and competing use charges, which reduced available surplus congestion revenue.
43 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 34 (May 21, 2025).

44 On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period allocated to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165 (2018).

in excess of FTR target allocations be distributed to ARR holders on a monthly basis. Under the MMU recommendation, the amount represented by each bar in Figure 13-14 would be assigned to ARR holders in every month.

Figure 13-13 Monthly surplus auction revenue and surplus congestion revenue: June 2017 through September 2025[45]

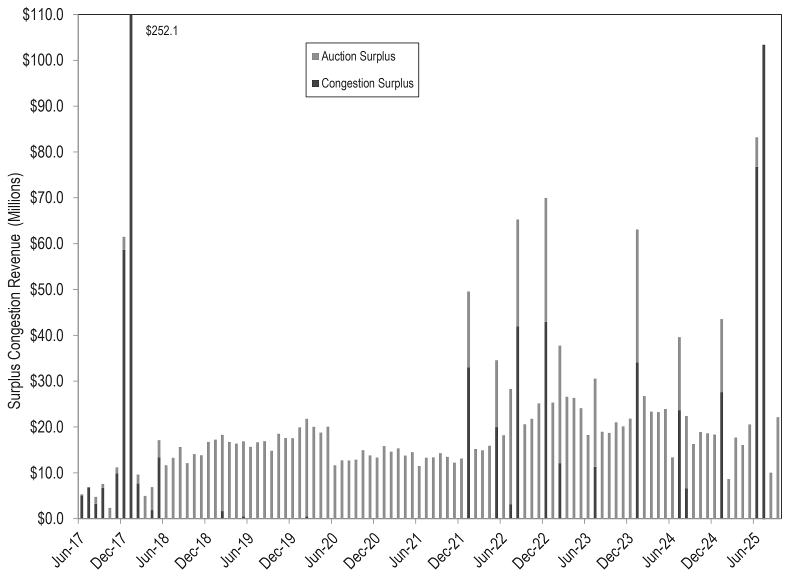


Figure 13-14 shows the increase or decrease in total accrued surplus for the planning period for each month (orange line). In Figure 13-14, if the FTR payments from the auction surplus are positive in a month (blue line above zero), that means that FTR payments in that month were dependent on FTR auction surplus from that month to cover the FTR target allocations in that month. If the change in the total accrued surplus for a month is positive, that means that there was surplus revenue (equal to the height of the orange bar) left over after paying FTR target allocations in that month from congestion or from auction revenue. This net surplus is carried until the end of the planning period and used to backfill FTR target allocations as needed before distributing to ARR holders. If the change in total accrued surplus for a month is negative, that means that were insufficient revenues, including the auction surplus, to pay FTR target allocations in that month. If the net surplus is negative at the end of the planning period, total revenue paid to FTRs will be lower than total FTR target allocations. Under the current rules, FTRs are made whole using surplus revenue from other months within the same planning period or by an uplift charge to all FTR holders at the end of the planning period. The final settlements are not known until the end of the planning period.

45 The bar for January 2018 is truncated.

In the 2024/2025 planning period there was not enough revenue from congestion plus auction surplus to pay FTR target allocations, resulting in a reduction to the entire planning period surplus of $196.2 million. ARR holders were required to subsidize FTR holders because congestion revenues were less than FTR target allocations.

In the first four months of the 2025/2026 planning period, $22.6 million of surplus auction revenue was transferred to FTR holders that would have been paid to ARR holders under the MMU's recommendation to distribute all FTR auction revenue to ARR holders every month, regardless of FTR funding levels. Day-ahead congestion increased by $548.9 million, 60.2 percent, from $912.0 million in the first four months of the 2024/2025 planning period to $1,460.9 million in the first four months of the 2025/2026 planning period. Target allocations increased by $378.6 million, 40.7 percent, from $931.2 million in the first four months of the 2024/2025 planning period to $1,309.8 million in the first four months of the 2025/2026 planning period. The actual day-ahead congestion ($1,460.9 million) was greater than the target allocations ($1,309.8 million) in the first four months of the 2025/2026 planning period. In July 2025, there was a large increase in Residual ARR target allocations without a corresponding increase in Monthly FTR Auction revenue, resulting in the first month with an ARR deficiency in the history of the ARR market. This disconnect between the ARR and FTR markets is a result of the fact that congestion is incorrectly defined as target allocations, i.e. the property rights for congestion in the current ARR/FTR market design are not correctly defined.

Figure 13-14 Monthly ARR surplus: June 2017 through September 2025[46]

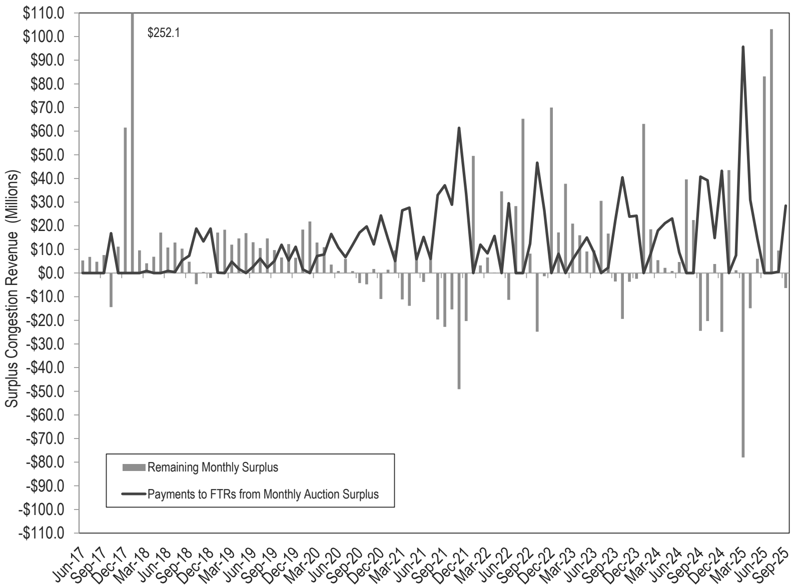
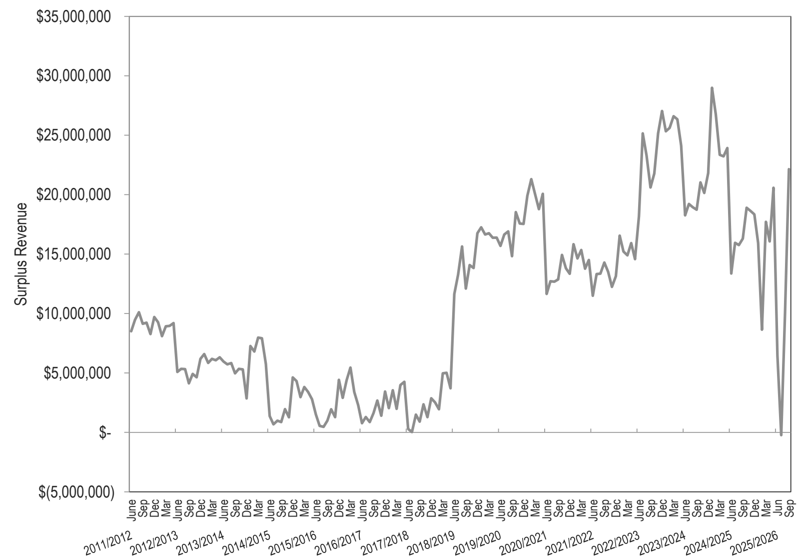


Figure 13-15 shows the surplus FTR auction revenue from the 2011/2012 planning period through the first four months of the 2025/2026 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market model can result in large differences in FTR auction surplus and ARR revenue from one planning period to another. Payments to FTRs have relied on payments from the surplus rather than from day-ahead congestion. The persistent mismatch between target allocations and day-ahead congestion and the use of the surplus are another illustration of the internal illogic and incoherence of the PJM FTR/ARR design.

FTR auction revenue is the value that FTR buyers assign to congestion rights that belong to ARR holders. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is inconsistent with the operation of a market that sellers are required to return some of the purchase price to buyers if the purchase is less profitable for buyers than expected. Auction revenue from the sale of FTRs should be distributed directly and completely to ARR holders.

Figure 13-15 Monthly FTR auction surplus: 2011/2012 through 2025/2026 planning period



46 The bar for January 2018 is truncated.

Table 13-44 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the first four months of the 2025/2026 planning period.

Table 13-44 Surplus FTR Auction Revenue: 2010/2011 through 2025/2026 planning period[47]

Planning Period	Surplus FTR Auction Revenue (Millions)	Surplus Day-Ahead Congestion (Millions)	Surplus Congestion Revenue (Millions)
2010/2011	$29.7	($1,218.7)	($449.3)
2011/2012	$108.9	($460.3)	($192.5)
2012/2013	$66.7	($328.5)	($292.3)
2013/2014	$71.7	($715.3)	($678.7)
2014/2015*	$29.0	$139.8	$139.6
2015/2016	$29.6	$56.4	$42.5
2016/2017	$27.9	$97.1	$72.6
2017/2018	$27.4	$344.0	$371.2
2018/2019	$180.8	($68.5)	$112.3
2019/2020	$217.8	($87.9)	$140.7
2020/2021	$166.1	($185.1)	($14.5)
2021/2022	$168.5	($198.0)	($29.5)
2022/2023	$289.2	($54.0)	$235.2
2023/2024	$264.4	($146.7)	$117.8
2024/2025	$196.2	($236.1)	($39.9)
2025/2026**	$38.4	$151.1	$189.8
Total	$1,912.4	($2,910.6)	($275.1)

*Start of counter flow "buy back"
**First four months of the 2025/2026 planning period

"Revenue Adequacy"

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs. If FTRs only returned congestion to FTR holders, there could be no such thing as revenue inadequacy.

As currently defined in PJM, FTR revenue adequacy simply compares day-ahead congestion revenues to FTR target allocations. (Target allocations are the day-ahead CLMP differences, shadow prices, between the source and sink of the FTR times the MW of the FTR. Congestion revenues are the day-ahead CLMP differences, shadow prices, between sources and sinks times the MW flow on the lines.) There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. There are systematic differences between FTR target allocations and actual congestion in aggregate and on a path by path basis. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment. Yet PJM treats target allocations as a guarantee of payment and takes what is termed surplus auction revenue from ARR holders (load) and gives it to FTR holders when day-ahead congestion revenues are not enough to cover all FTR target allocations.

Actual day-ahead congestion revenues are not a result of PJM's decisions about the FTR auction model, but result from the operation of the day-ahead energy market. As a result, the fewer FTRs sold, the higher the probability that congestion will exceed the sum of the FTR target allocations. For example, PJM's subjective decision to reduce available ARR/FTR supply in the ARR/FTR market model through outage selection for the 2014/2015 through 2016/2017 planning periods resulted in actual day-ahead congestion exceeding target allocations at the expense of a reduction in available ARRs and associated FTRs. PJM's decisions have included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced the FTRs made available for sale in FTR auctions. PJM's

47 Total congestion surplus not equal to the sum of the columns in years prior to the 2017/2018 planning period because other charges were subtracted from the congestion surplus.

actions have led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. Instead, PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. The direct assignment of balancing congestion (generally negative) and M2M payments to load beginning in the 2017/2018 planning period arbitrarily decreased congestion available for load and increased the congestion revenue available to pay FTR holders. PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing the supply of ARRs and FTRs. The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

Revenue adequacy for ARRs is, for practical purposes, a meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. For that reason, ARRs have unsurprisingly been defined to be revenue adequate for every auction to date. ARR revenue adequacy has nothing to do with the adequacy of ARRs as an offset to total congestion. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load, or even much less.

Total net FTR auction revenue for the 2024/2025 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $1,664.9 million. For the first four months of the 2025/2026 planning period, total net FTR auction revenue was $1,859.0 million.

Table 13-45 presents the PJM FTR revenue detail for the 2024/2025 planning period and the first four months of the 2025/2026 planning period. This includes ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[48] In this table, under the balancing congestion and M2M payment rules, any net negative congestion revenue is from day-ahead congestion and does not include balancing congestion. Any remaining surplus will be distributed to ARR holders at the end of the planning period, while any remaining deficiency will be charged to all FTR holders as FTR uplift at the end of the planning period. The actual surplus or deficiency for the planning period is not known until the end of the planning period. In the 2024/2025 planning period and the first four months of the 2025/2026 planning period, FTRs were paid part of the ARR auction surplus to ensure the payment of the FTR target allocations.

48 The final ARR values may change if load shifts.

Table 13-45 Total annual ARR and FTR revenue detail (Dollars (Millions)): 2024/2025 and 2025/2026 planning periods

Accounting Element	2024/2025	2025/2026*
ARR Information		
ARR Target Allocations	$1,448.1	$1,859.0
ARR Credits	$1,448.1	$1,859.0
FTR Auction Revenue	$1,664.9	$2,088.2
Annual FTR Auction Net Revenue	$1,475.3	$1,895.3
Long Term FTR Auction Net Revenue	$110.0	$153.0
Monthly Balance of Planning Period FTR Auction Net Revenue	$79.6	$39.9
Surplus Auction Revenue		
ARR Surplus (FTR Auction Revenue - ARR Credits)	$216.8	$229.2
ARR Payout Ratio	100%	100%
FTR Targets		
Positive Target Allocations	$2,731.0	$1,567.3
Negative Target Allocations	($573.4)	($257.5)
FTR Target Allocations	$3,304.4	$1,309.8
FTR Revenues		
ARR Surplus	$216.8	$229.2
Congestion		
Net Negative Congestion	$0.0	$0.0
Hourly Congestion Revenue	$2,494.9	$1,460.9
Surplus Congestion Revenues Distributed to Other Months	$52.9	$52.9
Total FTR Congestion Credits	$2,691.1	$1,499.5
FTR Payout Ratio		
Congestion	75.5%	111.5%
Congestion and ARR Surplus	98.8%	100.0%
Remaining Deficiency	$39.9	$0.0
Remaining Surplus	$0.0	$189.8

*First four months of the 2025/2026 planning period

FTR target allocations are defined based on hourly CLMP differences in the day-ahead energy market for FTR paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations but are capped at target allocations. Table 13-46 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month for the 2024/2025 planning period and the first four months of the 2025/2026 planning period. FTR revenues include congestion and surplus FTR auction revenue.

The total row in Table 13-46 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

Table 13-46 Monthly FTR accounting summary (Dollars (Millions)): 2024/2025 and 2025/2026 planning periods

Period	FTR Revenues	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus (with adjustments)	Monthly Credits Deficiency (with adjustments)
Jun-24	$168.6	$164.0	100.0%	$161.6	98.6%	$4.7	$0.0
Jul-24	$387.4	$347.8	100.0%	$343.2	98.7%	$39.6	$0.0
Aug-24	$272.4	$249.9	100.0%	$246.5	98.6%	$22.5	$0.0
Sep-24	$144.9	$169.2	85.7%	$166.8	98.6%	$0.0	($24.2)
Oct-24	$156.2	$176.3	88.6%	$173.7	98.5%	$0.0	($20.1)
Nov-24	$103.2	$99.3	100.0%	$97.8	98.5%	$3.9	$0.0
Dec-24	$236.6	$260.7	90.7%	$256.9	98.5%	$0.0	($24.1)
Jan-25	$377.6	$334.0	100.0%	$328.8	98.5%	$43.5	$0.0
Feb-25	$155.2	$154.0	100.0%	$151.6	98.4%	$1.2	$0.0
Mar-25	$213.2	$291.2	73.2%	$286.7	98.5%	$0.0	($78.0)
Apr-25	$201.8	$216.7	93.1%	$213.5	98.5%	$0.0	($14.9)
May-25	$274.0	$267.9	100.0%	$264.0	98.5%	$6.0	$0.0
Summary for Planning Period 2024/2025							
Total	$2,691.1	$2,731.0		$2,691.1			($39.9)
Jun-25	$430.0	$346.8	100.0%	$346.8	100.0%	$83.2	$0.0
Jul-25	$625.4	$522.0	100.0%	$522.0	100.0%	$103.4	$0.0
Aug-25	$186.8	$177.3	100.0%	$177.3	100.0%	$9.5	$0.0
Sep-25	$257.3	$263.6	97.6%	$263.6	100.0%	$0.0	$6.3
Summary for Planning Period 2025/2026*							
Total	$1,499.5	$1,309.8		$1,309.8		$189.8	

* First four months of the 2025/2026 planning period

Figure 13-16 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through September 2025. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-16 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. The payout ratio for months with a payout ratio less than 100 percent in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period and assigned to prior months.

Figure 13-16 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through September 2025

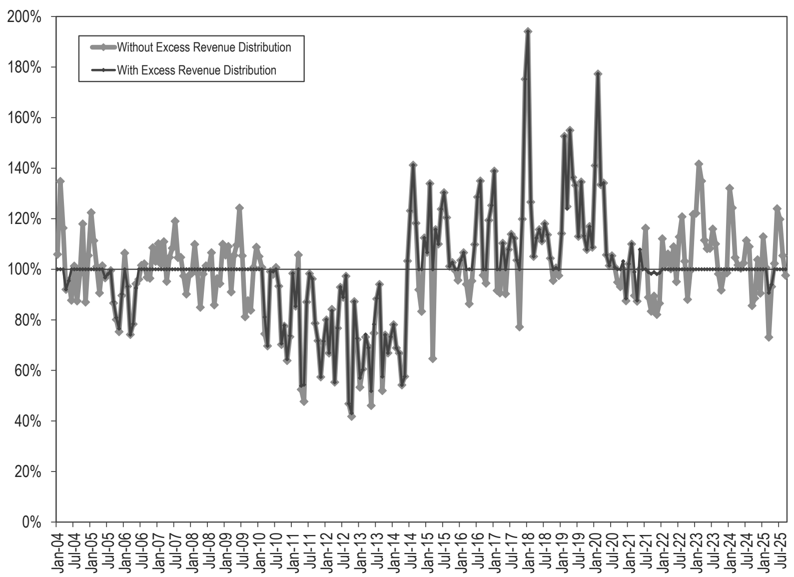


Table 13-47 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. The 2013/2014 planning period includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. Beginning with the 2018/2019 planning period payments to FTRs are limited to 100 percent of the target allocations.

The first four months of the 2025/2026 planning period had a payout ratio of 100.0 percent.

Table 13-47 Reported FTR payout ratio by planning period[49]

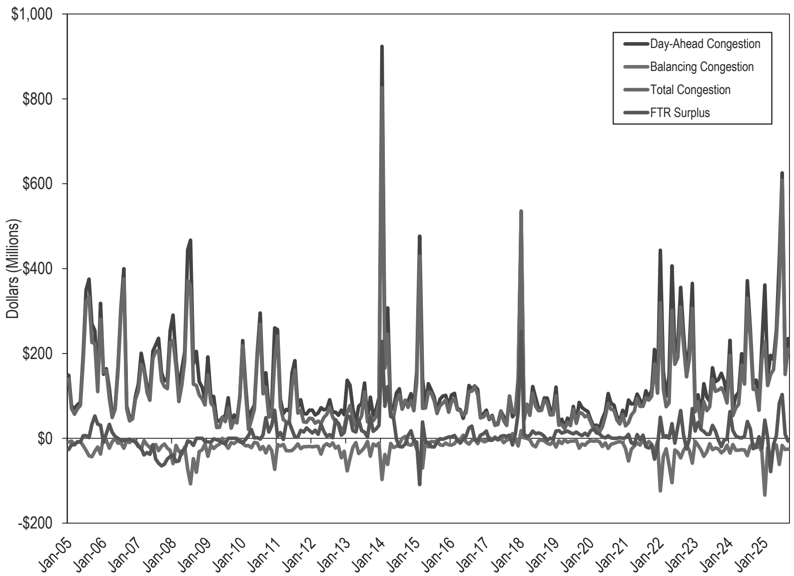
Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	116.2%
2015/2016	106.8%
2016/2017	112.6%
2017/2018	138.5%
2018/2019	100.0%
2019/2020	100.0%
2020/2021	98.7%
2021/2022	99.0%
2022/2023	100.0%
2023/2024	100.0%
2024/2025	98.8%
2025/2026*	100.0%

*First four months of 2025/2026

49 The actual payout ratios for the 2006/2007, 2007/2008, and 2008/2009 planning periods may have exceeded 100 percent.

Figure 13-17 shows the day-ahead balancing, total congestion and the FTR surplus from 2005 through September 2025.

Figure 13-17 FTR surplus and day-ahead, balancing and total congestion: 2005 through September 2025



Target Allocations and Congestion by Constraint Do Not Match

The path based ARR/FTR market design does not align with congestion based on actual network use. A comparison of the FTR target allocations for individual constraints to the day-ahead and total congestion by constraint provides evidence of this misalignment. Total congestion is the sum of day-ahead and balancing congestion. If FTR target allocations on some paths are significantly greater than actual congestion and FTR target allocations on other paths are significantly less than actual congestion, this is evidence of a serious flaw in the design. It is evidence of a mismatch between the definition of target allocations paid to FTR holders and the congestion that is the purported source of those payments.

FTR target allocations are the result of constraints on day-ahead paths in the energy market. Any specific FTR path may be affected by multiple constraints. Constraints that result in FTR target allocations greater than the congestion that results from those constraints mean that the FTR target allocations are greater than the actual congestion. Figure 13-18 shows the constraints that are the top 10 sources of positive FTR target allocations, for first four months of the 2025/2026 planning period. Figure 13-18 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraints. Constraints for which FTR target allocations were greater than total congestion resulted in $276.1 million of excess target allocations not funded by actual congestion. Such constraints include constraints in Figure 13-18, such as Lenox – North Meshoppen, which resulted in FTR target allocations that were 1.7 times larger than the corresponding total congestion. In order to pay FTRs their target allocations on these constraints, congestion from other constraints where congestion exceeds target allocations and auction surplus are used as the source. This is not consistent with an efficient market either for other FTR holders or for load.

Figure 13-18 Top ten constraint sources of positive FTR target allocations: June 2025 through September 2025

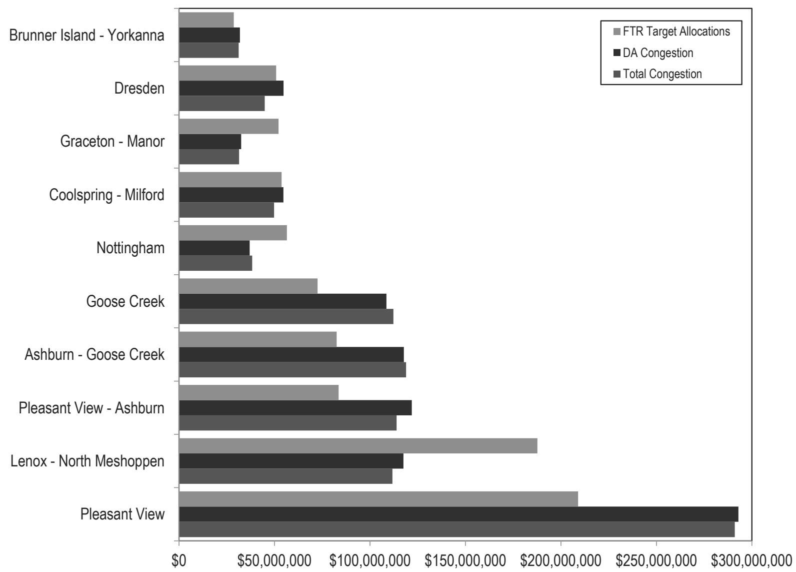


Figure 13-19 shows the hourly FTR target allocations, day-ahead congestion and balancing congestion for the Lenox – North Meshoppen constraint for the first four months of the 2025/2026 planning period. The Lenox – North Meshoppen constraint was the largest source of FTR target allocations during this period. The significant and variable difference between constraint specific FTR target allocations and constraint specific day ahead congestion provides evidence of the misalignment and over allocation of the path based FTR congestion rights relative to the actual network use of the physical energy market.

The Lenox – North Meshoppen constraint was a significant component of the overallocation of FTRs. FTRs routinely receive more target allocations than the congestion collected from the system because of the misalignment and over allocation of the path based FTR congestion rights relative to the actual network use of the physical energy market. The misalignment and overallocation of path based FTRs is exacerbated when line outages reduce the physical system capability between generation and load (the source of congestion revenue) relative to system capability assumed in the FTR market model. Figure 13-19 shows a large deviation between FTR target allocations and congestion for the Lenox – North Meshoppen constraint in December 2024. The main contributing factor for the deviation was the outage of the Grover – Scotch Hollow line.

Figure 13-19 Hourly FTR target allocations, total congestion, day-ahead congestion and balancing congestion for the Lenox – North Meshoppen constraint: June 2025 through September 2025

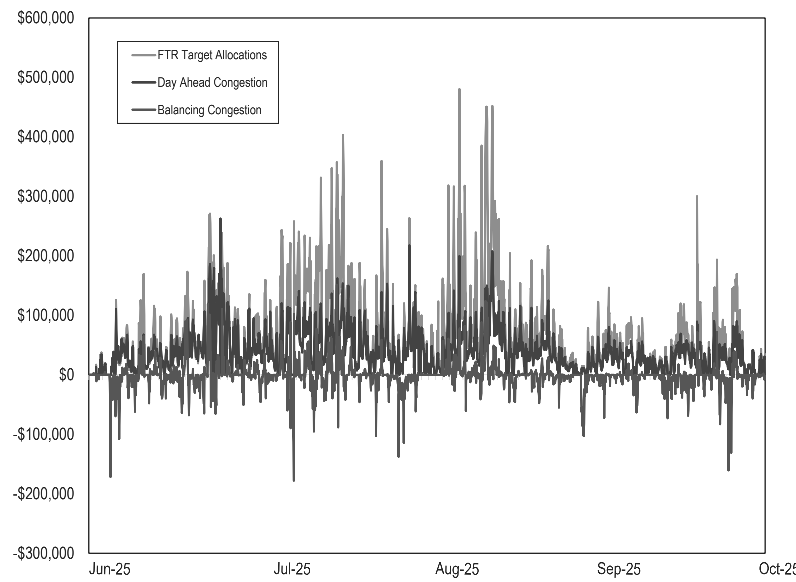
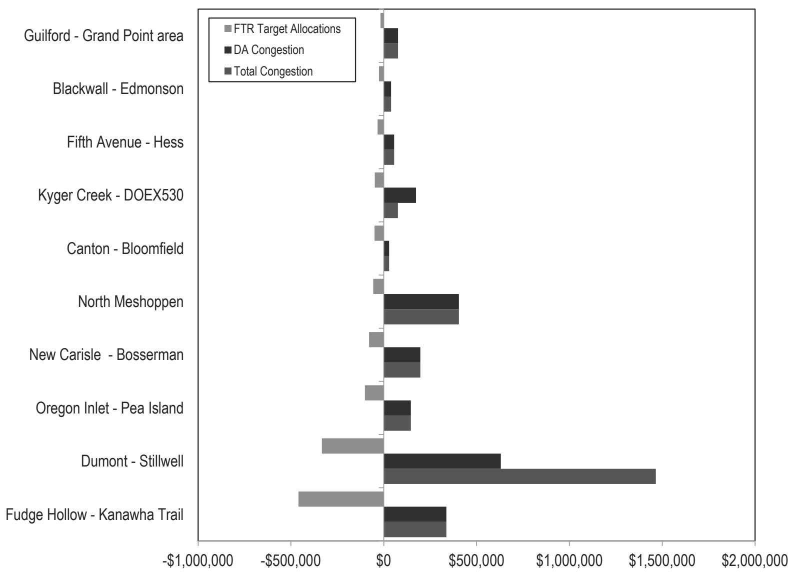


Figure 13-20 shows the constraints that are the top 10 sources of negative FTR target allocations (counter flow) for the first four months of the 2025/2026 planning period. Figure 13-20 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraints.

In the first four months of the 2025/2026 planning period, there were 29 constraints that were sources of negative target allocations. All of the 29 constraints that were sources of negative target allocations resulted in positive actual total congestion. Constraints that contribute positive congestion revenues and have negative FTR target allocations are a source of funds used in the settlement process to pay for FTR target allocations on FTR paths that are overallocated relative to actual congestion.

Figure 13-20 Top ten constraint sources of negative FTR target allocations: June 2025 through September 2025[50]



ARRs as an Offset to Congestion for Load

Load pays 100 percent of congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load to offset an unintended consequence of locational marginal pricing. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion paid by load and the congestion paid to load, in aggregate and on a specific load basis. These inconsistencies between actual network use and path based rights cause cross subsidies between ARR holders and FTR holders and among ARR holders. One result of this misalignment is that individual zones have very different offsets due to the location of their path based ARRs compared to their actual congestion costs from actual network use.

Table 13-48 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. The highlighted offsets are the actual offsets based on the rules that were effective in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total day-ahead congestion and the load share of balancing and M2M payments.

Total ARR and self scheduled FTR revenue offset only 66.6 percent of total congestion costs for the first four months of the 2025/2026 planning period.

50 New Carisle – Bosserman is the spelling provided in PJM data, rather than New Carlisle – Bosserman.

Table 13-48 ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2025/2026 planning periods

	Revenue								Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
Planning Period	ARR Credits	Unadjusted SS FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset	Cumulative Revenue	Offset
2011/2012	$515.6	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$775.0	103.4%	$585.5	78.1%	$663.8	88.5%	$775.0	103.4%
2012/2013	$356.4	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$530.7	101.1%	$263.2	50.2%	$306.9	58.5%	$530.7	101.1%
2013/2014	$339.4	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$826.5	44.2%	$556.3	29.7%	$556.3	29.7%	$826.5	44.2%
2014/2015	$487.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$872.2	64.2%	$678.4	50.0%	$967.8	71.3%	$872.2	64.2%
2015/2016	$641.8	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$860.2	90.4%	$745.5	78.4%	$892.3	93.8%	$860.2	90.4%
2016/2017	$648.1	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$813.1	104.1%	$729.6	93.4%	$872.1	111.7%	$813.1	104.1%
2017/2018	$429.6	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$694.2	58.2%	$592.8	49.7%	$883.1	74.1%	$592.8	49.7%
2018/2019	$531.6	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$655.87	96.4%	$525.3	77.2%	$621.3	91.4%	$621.3	91.4%
2019/2020	$547.6	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$637.9	144.1%	$491.7	111.1%	$627.9	141.8%	$627.9	141.8%
2020/2021	$392.7	$179.9	$899.6	($256.2)	$643.4	($43.2)	($0.0)	($0.0)	$529.31	82.3%	$316.4	49.2%	$316.4	49.2%	$316.4	49.2%
2021/2022	$469.7	$500.5	$2,069.2	($457.4)	$1,611.8	($104.6)	($2.9)	($2.9)	$865.6	53.7%	$509.9	31.6%	$509.9	31.6%	$509.9	31.6%
2022/2023	$998.7	$630.0	$2,223.5	($526.5)	$1,697.1	($80.6)	$65.1	$235.2	$1,548.2	91.2%	$1,167.4	68.8%	$1,337.5	78.8%	$1,337.5	78.8%
2023/2024	$912.1	$371.4	$1,618.9	($327.0)	$1,291.9	($44.1)	$24.6	$117.2	$1,239.4	95.9%	$981.2	76.0%	$1,073.7	83.1%	$1,073.7	83.1%
2024/2025	$954.7	$658.0	$2,494.8	($475.5)	$2,019.4	($124.2)	($9.6)	($9.6)	$1,488.6	73.7%	$1,127.7	55.8%	$1,127.7	55.8%	$1,127.7	55.8%
2025/2026*	$415.9	$413.1	$1,460.9	($136.4)	$1,324.6	$16.8	$59.8	$189.6	$845.8	63.9%	$752.4	56.8%	$882.2	66.6%	$882.2	66.6%
Total	$8,641.2	$5,099.5	$21,305.4	($4,167.3)	$17,138.1	($558.1)	$449.9	$2,065.7	$13,182.7	76.9%	$10,023.3	58.5%	$11,639.0	67.9%	$11,767.2	68.7%

*First four months of the 2025/2026 planning period

Table 13-48 illustrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

Table 13-49 shows the cumulative offset and shortfall using the rules that were effective in the given planning period to calculate the ARR/FTR revenue. The cumulative offset, beginning in the 2011/2012 planning period, is the sum of the revenue received for that planning period and all previous planning periods divided by the total congestion for that planning period and all previous planning periods. The cumulative shortfall is the cumulative difference between the ARR holders' revenue and the congestion they paid, for each planning period and the planning periods prior to each planning period.

From the 2011/2012 planning period through the first four months of the 2025/2026 planning period, the cumulative offset, the cumulative return of congestion to load, was only 68.7 percent based on the total congestion and the effective offset rules that were in place for each planning period. Load has been underpaid by $5.4 billion from the 2011/2012 planning period through the first four months of the 2025/2026 planning period. This is an increase of $0.5 billion from the $4.9 billion that load had been underpaid for the 2011/2012 planning period through the 2024/2025 planning period. The $5.4 billion is the difference between the total congestion column ($17.2 billion) and the total offset column ($11. billion) in Table 13-48.

Table 13-49 ARR and self scheduled FTR cumulative offset for ARR holders: 2011/2012 through 2025/2026 planning periods

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	103.4%	$25.3
2012/2013	102.4%	$31.2
2013/2014	67.8%	($1,012.9)
2014/2015	66.7%	($1,498.3)
2015/2016	70.9%	($1,589.2)
2016/2017	75.0%	($1,556.9)
2017/2018	71.0%	($2,156.7)
2018/2019	72.7%	($2,215.4)
2019/2020	76.3%	($2,030.2)
2020/2021	74.4%	($2,357.2)
2021/2022	68.0%	($3,459.1)
2022/2023	69.5%	($3,818.7)
2023/2024	70.7%	($4,036.8)
2024/2025	68.8%	($4,928.5)
2025/2026*	68.7%	($5,370.9)

*First four months of the 2025/2026 planning period

Zonal ARR Congestion Offset

Zonal ARR congestion offsets vary significantly across zones. There is no good reason that this should be the result of a system designed to return congestion to load. PJM has offered no explanation for this result. This outcome is a direct result of the flawed definition of congestion and of the method for assigning rights to congestion to ARR holders. The results show that path based ARR assignments in the current path based ARR/FTR design are not aligned with actual network use by load, and are therefore not aligned with how congestion is actually paid by load on actual network usage. Due to this misalignment of ARR rights relative to actual network usage, individual loads cannot claim the congestion they paid through assigned ARRs. One result of the misalignment of path based ARR rights are cross subsidies among ARR holders.

ARRs are allocated to zonal load based on historical generation to load transmission contract paths, in many cases based on 1999 contract paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load, including generation in the zone and outside the zone.[51]

Table 13-50 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue adjusted by the payout ratio for FTRs if below 100 percent; and the allocation of end of planning period surplus.[52] The offset for the first four months of the 2025/2026 planning period assigns the current surplus revenue at the end of the quarter to ARR holders. Table 13-50 also shows payments by load for balancing congestion and M2M payments. The total congestion offset paid to load is the sum of all of those credits and charges.

The zonal offset percentage shown in Table 13-50 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone.

51 *See* "Constraint Based Congestion Calculations," PJM ARR FTR Market Task Force (July 17, 2020) <https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx>.
52 See *2020 Annual State of the Market Report for PJM*, Volume 2, Section 11: Congestion and Marginal Losses

Table 13-50 Zonal ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2025/2026 planning period

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	$0.8	$0.1	($1.61)	$0.2	($0.6)	$18.2	($1.5)	($0.1)	$16.6	(3.3%)
AEP	$29.4	$19.2	($20.1)	$21.4	$49.9	$208.0	($19.0)	($1.1)	$187.9	26.6%
APS	$28.5	$10.6	($8.0)	$12.5	$43.5	$85.6	($7.7)	($0.4)	$77.5	56.1%
ATSI	$20.1	$1.1	($10.0)	$6.0	$17.2	$105.8	($9.4)	($0.5)	$95.8	18.0%
BGE	$70.4	$6.2	($4.7)	$21.5	$93.4	$61.5	($4.4)	($0.2)	$56.8	164.3%
COMED	$36.2	$1.0	($14.8)	$10.6	$33.0	$170.4	($14.0)	($0.8)	$155.6	21.2%
DAY	$4.6	$0.6	($2.7)	$1.5	$4.1	$26.0	($2.5)	($0.1)	$23.3	17.4%
DOM	$66.9	$346.0	($21.3)	$4.1	$395.8	$269.7	($20.2)	($1.1)	$248.4	159.3%
DPL	$41.3	$7.4	($3.4)	$1.2	$46.5	$42.0	($3.2)	($0.2)	$38.6	120.6%
DUKE	$14.0	($0.0)	($4.4)	$66.7	$76.2	$43.1	($4.2)	($0.2)	$38.7	197.1%
DUQ	$4.0	$0.2	($2.0)	$12.6	$14.7	$17.8	($1.9)	($0.1)	$15.8	93.1%
EKPC	$2.5	($0.0)	($2.1)	$0.7	$1.1	$21.6	($1.9)	($0.1)	$19.5	5.8%
EXT	$0.4	$0.0	($4.7)	$0.1	($4.3)	$29.9	($4.7)	$0.0	$25.2	(17.0%)
JCPLC	$1.9	$1.9	($4.3)	$0.8	$0.3	$48.2	($4.1)	($0.2)	$43.9	0.6%
MEC	$5.2	$1.3	($6.9)	$1.6	$1.2	$28.2	($6.7)	($0.1)	$21.3	5.7%
OVEC	$0.0	$0.0	($0.1)	$0.0	($0.1)	$1.4	($0.1)	($0.0)	$1.2	(12.3%)
PE	$17.1	$9.1	($2.3)	$6.1	$30.1	$25.3	($2.2)	($0.1)	$23.0	130.7%
PECO	$4.0	$0.2	($5.9)	$1.2	($0.5)	$61.2	($5.6)	($0.3)	$55.3	(0.8%)
PEPCO	$29.8	$5.4	($4.2)	$9.5	$40.4	$58.5	($4.0)	($0.2)	$54.3	74.4%
PPL	$21.0	$2.1	($5.9)	$6.3	$23.4	$62.7	($5.6)	($0.3)	$56.8	41.2%
PSEG	$17.1	$0.4	($6.7)	$5.1	$15.9	$73.2	($6.4)	($0.4)	$66.5	23.9%
REC	$0.8	$0.0	($0.2)	$0.2	$0.7	$2.7	($0.2)	($0.0)	$2.4	30.7%
Total	$415.9	$412.7	($136.4)	$189.8	$882.0	$1,460.9	($129.7)	($6.7)	$1,324.6	66.6%

The total congestion offset paid to loads in the first four months of the 2025/2026 planning period was 66.6 percent of congestion costs. The results vary significantly by zone. Loads in some zones, like BGE and DOM, receive substantially more in offsets than their total congestion payments. Loads in other zones, like EKPC, receive substantially less in offsets than their total congestion payments. Loads in some zones, like MEC, have higher balancing congestion and M2M charges than the load is able to offset with ARRs and FTRs, resulting in a negative total offset. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions.

The amount and proportion of the offset that can be realized by load serving entities via their ARR allocations varies by planning period. The offsets are a function of the assignment of ARRs relative actual network sources of congestion paid, the valuation of ARRs in the FTR auctions and the congestion revenue from self scheduled ARRs. If the prices for FTRs are high relative to realized congestion, the offset provided by ARR is increased relative to cases where the prices for FTRs are low relative to realized congestion. While the amount of congestion that is returned to the load varies by planning period, PJM's ARR/FTR design has consistently failed to return the congestion revenues to the load that paid it. It is not possible for load to recover all of the congestion that they pay under the current design in which the rights to congestion revenues are assigned based on fictitious contract paths.

Offset If All ARRs Are Held As ARRs

Table 13-51 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARRs holders held all their allocated ARRs in the 2023/2024, 2024/2025, and the first four months of the 2025/2026 planning periods and did not self schedule any. If ARR holders held all their allocated ARRs for the first four months of the 2025/2026 planning period, the ARR Target Allocations would have offset 39.9 percent of the congestion paid by load. However, the offset that would be received by individual zones varies widely, from -5.1 percent for MEC to 124.0 percent for BGE.

Table 13-51 Offset available to load if all ARRs are held: 2023/2024 through 2025/2026 planning periods

	23/24 Planning Period				24/25 Planning Period				25/26 Planning Period*			
	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset
ACEC	$4.9	($3.8)	$10.8	9.7%	$4.5	($5.4)	$18.8	(5.1%)	$0.8	($1.6)	$16.6	(4.6%)
AEP	$185.2	($50.4)	$201.8	66.8%	$160.6	($72.1)	$327.3	27.1%	$74.9	($20.1)	$187.9	29.2%
APS	$85.5	($22.4)	$87.6	72.1%	$96.9	($33.3)	$149.2	42.6%	$43.7	($8.0)	$77.5	46.0%
ATSI	$50.3	($25.6)	$99.4	24.8%	$61.9	($33.8)	$169.2	16.6%	$20.9	($10.0)	$95.8	11.4%
BGE	$145.8	($12.5)	$44.4	300.4%	$153.0	($18.2)	$79.9	168.7%	$75.1	($4.7)	$56.8	124.0%
COMED	$44.9	($31.4)	$215.9	6.3%	$55.3	($42.4)	$232.2	5.5%	$37.0	($14.8)	$155.6	14.3%
DAY	$13.3	($6.7)	$23.7	27.7%	$13.7	($8.8)	$39.1	12.5%	$5.1	($2.7)	$23.3	10.4%
DOM	$642.0	($52.0)	$181.8	324.6%	$430.5	($82.9)	$323.2	107.6%	$233.5	($21.3)	$248.4	85.4%
DPL	$69.6	($8.4)	$51.2	119.7%	$90.8	($13.9)	$70.7	108.8%	$44.0	($3.4)	$38.6	105.3%
DUKE	$52.1	($10.3)	$37.7	110.9%	$49.2	($13.3)	$55.2	64.9%	$14.3	($4.4)	$38.7	25.6%
DUQ	$8.6	($5.2)	$15.1	22.5%	$12.1	($6.8)	$25.1	21.0%	$4.2	($2.0)	$15.8	13.6%
EKPC	$6.5	($5.7)	$20.6	4.0%	$8.3	($8.1)	$32.2	0.7%	$2.5	($2.1)	$19.5	2.4%
EXT	$1.9	($9.6)	$26.4	(29.1%)	$1.2	($12.7)	$27.2	(42.1%)	$0.5	($4.7)	$25.2	(16.7%)
JCPLC	$4.6	($10.4)	$32.4	(18.1%)	$9.1	($14.6)	$54.8	(10.0%)	$3.0	($4.3)	$43.9	(3.2%)
MEC	$34.2	($6.7)	$21.8	126.3%	$24.2	($12.7)	$35.5	32.4%	$5.8	($6.9)	$21.3	(5.1%)
OVEC	($0.0)	($0.4)	$2.1	(19.1%)	$0.0	($0.5)	$3.6	(13.6%)	$0.0	($0.1)	$1.2	(12.3%)
PE	$22.2	($6.5)	$28.3	55.6%	$50.0	($9.6)	$43.7	92.5%	$21.4	($2.3)	$23.0	83.2%
PECO	$21.2	($14.9)	$42.3	14.8%	$29.8	($22.0)	$75.6	10.3%	$4.3	($5.9)	$55.3	(2.9%)
PEPCO	$65.4	($11.6)	$38.3	140.7%	$65.3	($17.0)	$69.3	69.8%	$33.1	($4.2)	$54.3	53.1%
PPL	$80.0	($15.6)	$57.9	111.2%	$68.1	($23.2)	$97.0	46.3%	$21.9	($5.9)	$56.8	28.1%
PSEG	$69.3	($16.4)	$50.3	105.0%	$81.1	($23.5)	$87.2	66.1%	$17.7	($6.7)	$66.5	16.5%
REC	$2.7	($0.6)	$2.2	98.8%	$3.1	($0.8)	$3.5	66.0%	$0.8	($0.2)	$2.4	21.6%
Total	$1,610.1	($327.0)	$1,291.9	99.3%	$1,468.7	($475.4)	$2,019.4	49.2%	$664.4	($136.4)	$1,324.6	39.9%

* First four months of the 2025/2026 planning period

Offset If All ARRs Are Self Scheduled

Table 13-52 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARR holders self scheduled all their ARRs received in the annual auction process as FTRs in the 2023/2024, 2024/2025, and the first four months of the 2025/2026 planning periods. Market rules allow ARRs available in the annual auction process to be self scheduled as FTRs. Any ARRs awarded monthly as residual ARRs cannot be self scheduled but provide ARR revenue based on monthly auction results. The calculated self scheduled FTR target allocations assume a 100 percent payout ratio. Residual ARRs cannot be self scheduled and are included in addition to the self scheduled FTR target allocations. If ARR holders had self scheduled all their allocated ARRs to FTRs for the first four months of the 2025/2026 planning period, the ARR Target Allocations would have offset 98.7 percent of the congestion paid by load. The results show that the recovery of congestion varies significantly by zone and that the load in some zones recovers more than the congestion paid and the load in other zones recovers less. This result is not consistent with a rational FTR/ARR design under which all load would be returned their congestion, but no more and no less.

Table 13-52 Offset available to load if all ARRs self scheduled: 2023/2024 through 2025/2026 planning periods

	23/24 Planning Period					24/25 Planning Period					25/26* Planning Period				
	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+ M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+ M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+ M2M	Offset
ACEC	$4.5	$0.0	($3.8)	$10.8	6.6%	$0.7	$0.0	($5.4)	$18.8	(25.3%)	$3.9	$0.0	($1.6)	$16.6	14.2%
AEP	$101.4	$3.2	($50.4)	$201.8	26.8%	$215.2	$4.7	($72.1)	$327.3	45.2%	$50.9	$0.0	($20.1)	$187.9	16.4%
APS	$77.5	$0.6	($22.4)	$87.6	63.5%	$133.7	$8.3	($33.3)	$149.2	72.9%	$43.9	$0.0	($8.0)	$77.5	46.3%
ATSI	$84.3	$0.1	($25.6)	$99.4	59.1%	$74.8	$0.1	($33.8)	$169.2	24.3%	$31.1	$0.0	($10.0)	$95.8	22.0%
BGE	$190.3	$0.0	($12.5)	$44.4	400.6%	$186.1	$0.2	($18.2)	$79.9	210.4%	$109.4	$0.9	($4.7)	$56.8	185.9%
COMED	$83.0	$0.0	($31.4)	$215.9	23.9%	$76.6	$0.1	($42.4)	$232.2	14.8%	$158.1	$0.0	($14.8)	$155.6	92.1%
DAY	$12.3	$0.2	($6.7)	$23.7	24.4%	$15.3	$0.9	($8.8)	$39.1	18.9%	$3.6	$0.0	($2.7)	$23.3	4.1%
DOM	$292.8	$0.5	($52.0)	$181.8	132.8%	$32.4	$8.5	($82.9)	$323.2	(13.0%)	$646.2	$41.4	($21.3)	$248.4	268.2%
DPL	$87.8	$0.0	($8.4)	$51.2	155.3%	$627.0	$0.5	($13.9)	$70.7	868.1%	$77.9	$7.9	($3.4)	$38.6	213.6%
DUKE	$55.8	$0.0	($10.3)	$37.7	120.8%	$88.7	$0.2	($13.3)	$55.2	136.8%	$15.4	$0.1	($4.4)	$38.7	28.6%
DUQ	$19.7	$0.0	($5.2)	$15.1	96.3%	$12.7	$0.0	($6.8)	$25.1	23.4%	$4.2	$0.0	($2.0)	$15.8	13.6%
EKPC	$8.7	$0.0	($5.7)	$20.6	14.4%	$4.8	$1.1	($8.1)	$32.2	(7.0%)	$2.4	$0.0	($2.1)	$19.5	1.6%
EXT	$1.3	$0.0	($9.6)	$26.4	(31.4%)	$1.2	$0.0	($12.7)	$27.2	(42.0%)	$0.6	$0.0	($4.7)	$25.2	(16.5%)
JCPLC	$6.1	$0.0	($10.4)	$32.4	(13.3%)	$9.1	$0.1	($14.6)	$54.8	(9.6%)	$4.2	$0.1	($4.3)	$43.9	(0.2%)
MEC	$5.4	$0.0	($6.7)	$21.8	(6.3%)	$18.6	$0.3	($12.7)	$35.5	17.6%	$13.8	$0.1	($6.9)	$21.3	32.9%
OVEC	($0.0)	$0.0	($0.4)	$2.1	(18.0%)	($0.0)	$0.0	($0.5)	$3.6	(13.6%)	$0.0	$0.0	($0.1)	$1.2	(12.4%)
PE	$46.0	$0.0	($6.5)	$28.3	139.5%	$6.4	$0.2	($9.6)	$43.7	(6.9%)	$60.7	$0.0	($2.3)	$23.0	253.9%
PECO	$29.0	$0.0	($14.9)	$42.3	33.4%	$119.8	$0.0	($22.0)	$75.6	129.5%	$3.5	$0.0	($5.9)	$55.3	(4.4%)
PEPCO	$73.3	$0.0	($11.6)	$38.3	161.4%	$90.1	$0.3	($17.0)	$69.3	105.9%	$82.9	$0.0	($4.2)	$54.3	144.9%
PPL	$37.1	$0.0	($15.6)	$57.9	37.1%	$107.3	$0.6	($23.2)	$97.0	87.4%	$65.3	$0.0	($5.9)	$56.8	104.5%
PSEG	$49.3	$0.0	($16.4)	$50.3	65.3%	$66.8	$0.1	($23.5)	$87.2	49.8%	$13.5	$0.0	($6.7)	$66.5	10.2%
REC	$3.7	$0.0	($0.6)	$2.2	143.6%	$4.4	$0.0	($0.8)	$3.5	104.2%	$1.9	$0.0	($0.2)	$2.4	69.4%
Total	$1,269.4	$4.5	($327.0)	$1,291.9	73.3%	$1,891.6	$26.3	($475.4)	$2,019.4	71.4%	$1,393.3	$50.5	($136.4)	$1,324.6	98.7%

* First four months of the 2025/2026 planning period

ARR Allocation and Congestion In and Out of Zone

Table 13-53 shows the share of ARR MW for the 2023/2024, 2024/2025, and 2025/2026 planning periods with paths that source inside and outside the zone where the ARR load is located (see Table 13-4) and the proportion of congestion that results from constraints that are inside and outside the zone for the 2023/2024, 2024/2025 and the first four months of the 2025/2026 planning periods. Table 13-53 allows a comparison of externally sourced ARRs with the congestion that results from external constraints. For example, 94.6 percent of ACEC congestion in the the first four months of the 2025/2026 planning period results from constraints that are outside of the zone, but only 55.9 percent of ACEC ARRs originate outside the zone for the 2025/2026 planning period ARR allocations.

Table 13-53 illustrates one of the fundamental issues with the contract path based approach to ARR/FTR design. In the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load, but the assignment of ARRs is inconsistent with that fact. This inconsistency makes it impossible for load to match ARRs with the actual sources of congestion.

Table 13-53 ARR Allocation and Congestion from inside and outside zone: 2023/2024, 2024/2025 and 2025/2026 planning periods

	2023/2024 ARRs		2023/2024 Congestion		2024/2025 ARRs		2024/2025 Congestion		2025/2026 ARRs		2025/2026* Congestion	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	49.1%	50.9%	97.2%	2.8%	55.1%	44.9%	98.1%	1.9%	44.1%	55.9%	94.6%	5.4%
AEP	10.1%	89.9%	89.1%	10.9%	9.4%	90.6%	86.2%	13.8%	13.9%	86.1%	92.1%	7.9%
APS	17.3%	82.7%	96.2%	3.8%	15.9%	84.1%	91.9%	8.1%	11.5%	88.5%	98.9%	1.1%
ATSI	33.2%	66.8%	95.8%	4.2%	35.1%	64.9%	96.7%	3.3%	41.5%	58.5%	97.4%	2.6%
BGE	38.0%	62.0%	86.5%	13.5%	39.9%	60.1%	87.7%	12.3%	49.4%	50.6%	95.0%	5.0%
COMED	0.0%	100.0%	58.6%	41.4%	0.1%	99.9%	77.6%	22.4%	0.0%	100.0%	75.0%	25.0%
DAY	87.2%	12.8%	100.0%	0.0%	92.6%	7.4%	100.0%	0.0%	79.9%	20.1%	100.0%	0.0%
DOM	0.4%	99.6%	87.8%	12.2%	2.0%	98.0%	65.7%	34.3%	0.5%	99.5%	34.1%	65.9%
DPL	23.2%	76.8%	61.9%	38.1%	26.0%	74.0%	46.2%	53.8%	28.7%	71.3%	63.7%	36.3%
DUKE	45.0%	55.0%	94.6%	5.4%	49.1%	50.9%	97.2%	2.8%	49.8%	50.2%	91.8%	8.2%
DUQ	96.2%	3.8%	99.8%	0.2%	97.0%	3.0%	97.4%	2.6%	91.2%	8.8%	99.6%	0.4%
EKPC	100.0%	0.0%	99.8%	0.2%	100.0%	0.0%	99.2%	0.8%	99.6%	0.4%	97.8%	2.2%
EXT	100.0%	0.0%	94.4%	5.6%	100.0%	0.0%	95.3%	4.7%	100.0%	0.0%	91.0%	9.0%
JCPL	34.6%	65.4%	97.9%	2.1%	58.9%	41.1%	96.5%	3.5%	72.2%	27.8%	100.0%	0.0%
OVEC	38.8%	61.2%	80.0%	20.0%	38.7%	61.3%	55.9%	44.1%	30.2%	69.8%	98.5%	1.5%
MEC	100.0%	0.0%	91.1%	8.9%	66.7%	0.0%	93.4%	6.6%	100.0%	0.0%	98.7%	1.3%
PE	16.2%	83.8%	86.2%	13.8%	24.6%	75.4%	76.0%	24.0%	26.5%	73.5%	84.6%	15.4%
PECO	21.6%	78.4%	90.2%	9.8%	6.9%	93.1%	90.6%	9.4%	2.3%	97.7%	95.9%	4.1%
PEPCO	47.2%	52.8%	99.8%	0.2%	46.9%	53.1%	99.5%	0.5%	24.1%	75.9%	98.4%	1.6%
PPL	2.6%	97.4%	92.0%	8.0%	5.8%	94.2%	89.7%	10.3%	1.0%	99.0%	89.7%	10.3%
PSEG	47.8%	52.2%	99.2%	0.8%	54.6%	45.4%	99.3%	0.7%	53.5%	46.5%	99.9%	0.1%
REC	100.0%	0.0%	83.4%	16.6%	100.0%	0.0%	79.6%	20.4%	100.0%	0.0%	98.4%	1.6%
Total	22.1%	77.9%	85.6%	14.4%	22.4%	77.6%	84.5%	15.5%	21.4%	78.6%	80.6%	19.4%

*first four months of the 2025/2026 planning period for congestion

Credit

There were two payment defaults and no collateral defaults in the first nine months of 2025. The two payment defaults were from the same member and have not been cured. The total payment defaults were $30,537.03.

On December 21, 2021, PJM submitted a change to the credit rules to FERC.[53] PJM proposed to replace the current credit calculation, which is largely based on a weighted average historical FTR value, with an initial margin based on a risk confidence interval from an Historical Simulation Initial Margining (HSIM) analysis model. PJM's proposal included the use of a 97 percent confidence interval, meaning a 97 percent probability that the initial margin collected would cover potential default costs.

On February 28, 2022, FERC rejected PJM's filing recommending a 97 percent confidence interval because the record did not support 97 percent.[54] FERC instituted a Section 206 proceeding, but recognized that PJM could propose revisions through a Section 205 filing. On June 3, 2022, PJM submitted the same change to the credit rules as the December 21, 2021, filing to FERC.[55] The June 3, 2022, filing included a cost /enefit analysis for the proposed use of a 97 percent confidence interval compared to the use of a 99 percent confidence interval. The MMU objected to PJM's filing and proposed a 99 percent confidence interval, with a transition to a 100 percent confidence interval.[56] On September 21, 2023, FERC directed PJM to use a 99 percent confidence level in the HSIM model.[57]

The most fundamental point is that if costs are shifted from FTR buyers to other market participants, no logical cost-benefit analysis can show that the other market participants benefit in any way. Under the current default rules, the cost of default is socialized to all market participants, not just those participating in the FTR market. The 99 percent confidence interval places more of the risk where it belongs, on the FTR market participants that are engaged in the risky behavior, than the 97 percent confidence interval. The goal of internalizing as much of the risk to the FTR participants as possible, where it belongs, could be more directly addressed either by using 100 percent or by directly assigning the risk to those in the FTR market rather than all market participants.

The PJM minimum credit requirements (minimum tangible net worth and minimum tangible assets) were set as fixed dollar amounts in 2011 in FERC Order No. 741 based on whether the market participant held FTRs. PJM has been reviewing the minimum credit requirements in the Risk Management Committee. The MMU and PJM developed a joint package to increase the fixed minimum credit requirements to be consistent with updated risks. The proposal was approved by the Risk Management Committee on October 22, 2025.[58]

Treatment of Defaulted Portfolios

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market and continues to accrue revenues and/or charges and must be reconciled. Under this method, PJM leaves the participant's positions unchanged, lets the positions settle at day-ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends that the defaulted FTRs be canceled rather than holding or liquidating them.[59] Canceling the FTRs would release the FTRs to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There would be no discretion necessary to settle the defaulted position and the losses would be contained within the ARR/FTR market.

Cancellation of a defaulting portfolio does not change congestion. Cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential

53 *See* "Revisions to PJM's FTR Credit Requirement and Request for 28-Day Comment Period," Docket No. ER22-000 (December 21, 2021).
54 See 178 FERC ¶ 61,146.
55 See "Revisions to PJM's FTR Credit Requirement," Docket No. ER22-2029-000 (June 3, 2022).
56 See Comments of the Independent Market Monitor for PJM, Docket No. ER22-2029-000 et al. (October 31, 2022).
57 See 184 FERC ¶ 61,168.
58 See "Agenda," PJM Risk Management Committee (October 22, 2025). <https://www.pjm.com/-/media/DotCom/committees-groups/committees/rmc/2025/20251022/20251022-agenda.pdf>
59 See Comments of the Independent Market Monitor for PJM, Docket No. ER18-2068-000 (August 16, 2018).

simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs would isolate the costs of the default to those participating in and benefitting from the FTR market.

FTR Forfeitures

By order issued January 19, 2017, the Commission determined that the FTR forfeiture rule is just and reasonable and "...serves to deter such manipulation" related to virtual transaction cross product manipulation.[60] The Commission identified four main tenets with which the Forfeiture Rule must comply, including that it: deter manipulation, provide transparency allowing participants to modify their behavior, base forfeitures on an individual participant's actions and is not punitive.[61]

The point of the FTR forfeiture rule is to avoid an inefficient and costly market power mitigation process and to establish an objective rule that prevents manipulation of the FTR market. The FTR forfeiture rule is designed to remove the incentive to engage in manipulation. The rule does not result in findings of manipulation.[62]

The FTR forfeiture rule considers the impact of a participant's net virtual transaction portfolio on all constraints.[63] If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the constraint line limit, and that constraint affects an individual FTR's target allocation by $0.01 or more, the participant's net virtual portfolio increased the value of the FTR, and the FTR is subject to FTR forfeiture. The FTR forfeiture also requires that congestion on the FTR path in the day ahead market be greater than congestion on that path in the real time market.

60 See 158 FERC ¶ 61,038 at P 33 (2017).
61 See *id.* at P 62.
62 *See* "Protest and Motion for Rejection of the Independent Market Monitor for PJM," Docket No. EL20-41 (June 1, 2020).
63 A modified FTR forfeiture rule was implemented effective January 19, 2017. See *2019 Annual State of the Market Report for PJM*, Volume 2, Section 13: Financial Transmission Rights for the full history.

The FTR forfeiture rule does not require FTR holders to pay penalties. The FTR forfeiture rule does not affect the profits or losses of virtual activity. The FTR forfeiture rule, if triggered by a participant's virtual portfolio, results in forfeiting only FTR profits and only in the specific hours for which the rule is violated. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Even when FTR profits are forfeited, the value that the buyer assigned to congestion in the FTR auction (the price paid) is not affected. For example, if a buyer paid $5.00/MWh for congestion and congestion was $5.00/MWh, the forfeiture would be zero. If congestion were $7.00/MWh, the forfeiture would be $2.00/MWh. Market participants understand the relationship between FTR and virtual positions in detail and can avoid violating the FTR forfeiture rule if they choose to do so.

The FTR forfeiture rule is less effective than initially intended as a result of the element of the rule requiring that day-ahead congestion on the FTR path be greater than real-time congestion the same path. As a result of model differences, there is a significant opportunity for virtual participants to profit from differences between day-ahead and real-time prices without driving the prices together, termed false arbitrage. As a result, FTR holders can use virtual positions to make their FTR positions more valuable without violating the rule.

The FTR forfeiture rule has not reduced participation in the PJM FTR market or participation in virtual activity. There has been an increase in the number of participants in the FTR market since the implementation of the new FTR forfeiture rule, and a decrease in the number of participants with forfeitures.

On June 24, 2019, PJM implemented a new method to calculate the hourly cost of an FTR only for hours in which it is effective.[64] Beginning with the September 2019 bill, PJM began billing using the correct hourly cost calculation. For the 2020/2021 planning period, total FTR forfeitures were $4.6 million.

On May 20, 2021, FERC issued an order ruling the $0.01 definition of an increase in the value of an FTR unjust and unreasonable, but upheld the other

64 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).

parts of PJM's forfeiture rule.[65] In this order, FERC required PJM to modify the FTR forfeiture rule and submit a compliance filing. As a result, there was no FTR forfeiture rule in place from May 21, 2021 until February 1, 2022. These months have zero forfeiture in Figure 13-21.

On June 21, 2021, PJM filed a request for clarification, or alternatively rehearing.[66] PJM asked that FERC clarify the status of the forfeitures that were assessed over the four years between the initial FERC order for a compliance filing, and their order rejecting PJM's compliance filing. On July 19, 2021, PJM made a compliance filing to address FERC's concerns with the $0.01 element of the FTR forfeiture rule.[67] PJM's compliance filing eliminated that element and replaced it with a constraint based FTR forfeiture. The forfeiture is based on the increased value of each constraint that violates the rule, determined by the shadow price multiplied by the net dfax on that constraint. This change meets FERC's previously established criteria established under the initial FERC order and creates a more precise FTR forfeiture value, to meet the criteria established under the new FERC order.

On January 31, 2022, FERC accepted PJM's July 19, 2021 compliance filing to implement FTR forfeitures using a constraint based method, effective February 1, 2022.[68]

Figure 13-21 shows the monthly FTR forfeitures under the FTR forfeiture rules in effect from January 19, 2017, through September 30, 2025. As required by the FERC order, PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the period from January 2017 through September 2017, participants did not have good information about the level of their FTR forfeitures, so they could not accurately modify their bidding behavior to avoid FTR forfeitures. After September 2017, participants received more timely information on their FTR forfeitures. Calculations of forfeitures under the new constraint specific rule from February 1, 2022, through September 30, 2025, are included in Figure 13-21.

65 See 175 FERC ¶ 61,137 (2021).
66 See Request for Clarification or, in the Alternative, Rehearing of PJM Interconnection, LLC, FERC Docket No. ER17-1433-000 (June 21, 2021).
67 *See* "FTR Forfeiture Rule Compliance Filing," FERC Docket No. ER17-1433 (July 19, 2021).
68 See 178 FERC ¶ 61,079, *reh'g denied*, 179 FERC ¶ 61,010 (2022), *affirmed*, XO Energy MA, LPC, et al. v. FERC, Case No. 22-1096 (D.C. Cir. January 24, 2023), *affirmed en banc*, XO Energy MA, LPC, et al. v. FERC, Case No. 22-1096 (D.C. Cir. September 13, 2023).

Figure 13-21 Monthly FTR forfeitures for physical and financial participants: January 2017 through September 2025

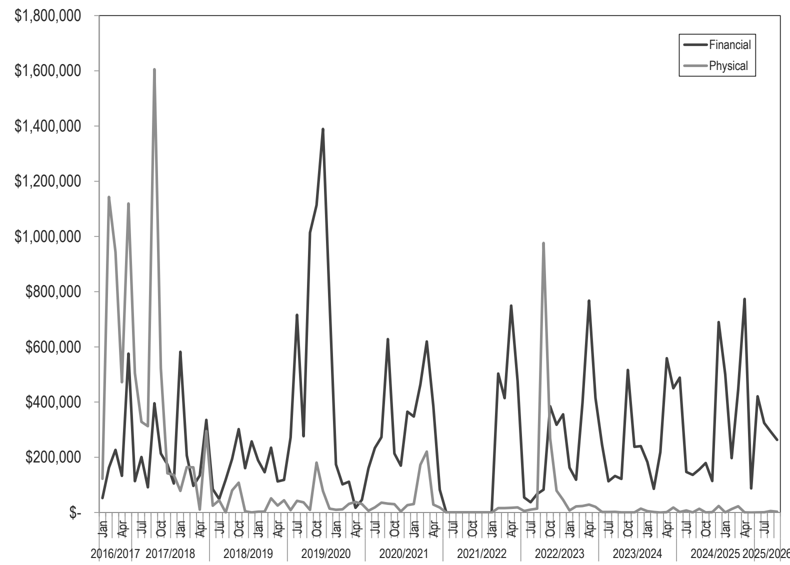


Table 13-54 shows the monthly FTR forfeitures by organization type for the 2024/2025 planning period and the first four months of the 2025/2026 planning period. For the first four months of the 2025/2026 planning period there were $1,312,218 in FTR forfeitures, up 38.0 percent from $951,033 in the same period of the 2024/2025 planning period.

Table 13-54 Monthly FTR forfeitures by organization type: June 2024 through September 2025

	Organization Type		
Month	Physical	Financial	Total
Jun-24	$2,062.39	$488,478.10	$490,540.49
Jul-24	$7,263.55	$147,024.31	$154,287.86
Aug-24	$265.40	$136,407.60	$136,672.99
Sep-24	$13,609.35	$155,922.29	$169,531.63
Oct-24	$153.22	$179,545.06	$179,698.29
Nov-24	$1,159.23	$114,091.82	$115,251.06
Dec-24	$23,393.12	$689,808.14	$713,201.26
Jan-25	$538.39	$500,477.32	$501,015.71
Feb-25	$12,543.78	$197,063.07	$209,606.85
Mar-25	$22,717.56	$446,139.20	$468,856.76
Apr-25	$638.34	$773,771.75	$774,410.09
May-25	$17.41	$87,239.94	$87,257.35
Summary for 2024/2025 Planning Period			
Total	$84,361.73	$3,915,968.60	$4,000,330.34
Jun-25	$615.50	$420,868.10	$421,483.61
Jul-25	$1,055.22	$324,455.09	$325,510.31
Aug-25	$5,596.14	$293,350.91	$298,947.05
Sep-25	$3,094.75	$263,182.16	$266,276.91
Summary For 2025/2026 Planning Period*			
Total	$10,361.61	$1,301,856.26	$1,312,217.87

*First four months of the 2025/2026 plannning period

State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC

Independent Market Monitor for PJM

2021

3.10.2022

Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM), and is also known as the Independent Market Monitor for PJM (IMM), submits this *2021 Annual State of the Market Report for PJM.*[2] [3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement (RAA), the Consolidated Transmission Owners Agreement (CTOA) or other tariffs that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M.

3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2021 Annual State of the Market Report for PJM.*

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Introduction

2021 in Review

Reliability is a core goal of PJM. Maintaining and improving competitive markets should also be a core goal of PJM. The goal of competition in PJM is to provide customers reliable wholesale power at the lowest possible price, but no lower. The PJM markets have done that. The PJM markets work, even if not perfectly. The results of PJM markets were reliable in 2021. The results of the energy market were competitive in 2021. The results of the 2021/2022 and 2022/2023 base capacity auctions were not competitive, but the Commission resolved the core underlying issue, the overstated market seller offer cap in the capacity market, prior to the 2023/2024 base capacity auction. The PJM markets bring customers the benefits of competition.

Markets provide incentives for innovation and efficiency. Organized, competitive wholesale power markets are the best way to facilitate the least cost path to decarbonization. Renewables can compete, without guaranteed long term contracts. Innovation will occur in renewable technologies in unpredictable and beneficial ways. But the PJM markets are not perfect. Significant changes to the core market design continue, including some that improve markets and some that do not. Significant issues with the core market design remain. It is not guaranteed that the market design will successfully adapt to the changing realities, including the role of renewable and intermittent resources, the role of distributed resources, the role of regulated EDCs in competitive wholesale power markets, and the role of states in subsidizing resources.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices for both price decreases and price increases. Energy prices increased significantly in 2021 from the very low levels in 2020. The real-time load-weighted average LMP in 2021 increased 82.8 percent from 2020, from $21.77 per MWh to $39.78 per MWh, the largest annual percent increase since the start of PJM markets in 1999, although not the largest dollar per MWh increase. Of the $18.02 per MWh increase, 72.7 percent was a direct result of higher fuel and emission costs, particularly higher natural gas prices. The real-time hourly average load in 2021 increased by 3.6 percent from 2020, from 84,584 MWh to 87,606 MWh.

The total price of wholesale power increased from $44.59 per MWh in 2020 to $65.14 per MWh in 2021, an increase of 46.1 percent. Energy, capacity and transmission charges are the three largest components of the total price of wholesale power, comprising 97.5 percent of the total price per MWh in 2021. Starting in the third quarter of 2019, for the first time since the start of the RPM capacity market design in 2007, the cost of transmission per MWh of wholesale power is higher than the cost of capacity.

Higher gas costs and higher power prices changed the relative economics of coal and gas units in 2021. Coal generation increased 17.8 percent and gas generation decreased 2.4 percent in 2021 compared to 2020. The changes in relative fuel prices slowed but did not change the long term decline in the share of coal and the increase in the share of gas. The share of total PJM energy produced from coal was 22.2 percent in 2021, down from 54.9 percent in 2008, and the share of energy produced from natural gas was 37.7 percent, greater than any other fuel source, up from 7.4 percent in 2008. The role of gas fired generation highlights the importance of ensuring that PJM has real time, detailed and complete information on the gas supply arrangements of all generators and that PJM consider rules requiring capacity resources to have firm fuel supplies. It is also essential that FERC consider and address the implications of the inconsistencies between the gas pipeline business model and the power producer business model and the issue of market power in the gas commodity market under extreme weather conditions.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Theoretical net revenues from the energy market increased for all unit types in 2021 compared to 2020. Theoretical energy net revenues increased by 76 percent for a new combustion turbine, 78 percent for a new combined cycle, 642 percent (from a level near zero in 2020) for a new coal unit, and 86 percent for a new nuclear plant. In 2021, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the capacity market in providing incentives for continued operation and investment. In 2021, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units. In 2021, a theoretical new combined cycle plant would have received sufficient net revenue to cover levelized total costs in 14 of the 20 PJM zones. But no theoretical new combustion turbine, coal plant, nuclear plant, or diesel plant would have received sufficient net revenue to cover levelized total costs in any zone.

Changes in forward energy market prices significantly affect the expected profitability of nuclear plants in PJM. Based on forward prices as of January 3, 2022, for energy, and known forward prices for capacity, all the nuclear plants in PJM are expected to cover their annual avoidable costs in 2022, based on NEI average costs. None of the currently subsidized nuclear plants in PJM need a subsidy for 2022 in order to cover their avoidable costs.

If more PJM states decide that carbon is a pollutant with a negative value, a market approach to carbon is preferred to an inefficient technology or unit specific subsidy approach or inconsistent RPS rules that in some cases subsidize carbon emitting resources. Delaware, Maryland, New Jersey and Virginia were members of RGGI in 2021. Virginia joined RGGI on January 1, 2021. Pennsylvania had planned to join RGGI on January 1, 2022 but has been delayed due to actions by the Pennsylvania legislature. Implementation of a carbon price is a market approach which would let market participants respond in efficient and innovative ways to the price signal rather than relying on planners to identify specific technologies or resources to be subsidized. Implementation of a carbon price using RGGI or a similar market mechanism by the states would mean that the states control the carbon price and that no FERC approval would be required and no PJM rule changes would be required. The carbon price would become part of the marginal costs of power plants and the impacts on production and consumption decisions would be market based. States would control the resulting revenues. This is the case regardless of the number of PJM states that join RGGI or a similar market.

The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to all PJM states in order to permit states to consider the development of a multistate framework that could benefit all states: for REC market design; for potential agreement on carbon pricing; for potential agreement on the distribution of carbon pricing revenues; and for coordination with PJM wholesale markets.

A number of PJM states are pursuing direct approaches to environmental issues including mandating the closure of emitting resources and capping emissions.

RECs (renewable energy credits) are an important mechanism used by PJM states to implement environmental policy. RECs affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar.

In the absence of a PJM market carbon price, a single, transparent PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor. Such a market would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. The market could also facilitate entry by renewable resources by reducing the risks associated with lack of transparent market data and ensuring competitive prices.

Despite suggestions that PJM needs a flexibility product, the PJM fleet already includes the flexibility needed to offset the fluctuations in output assumed to be inherent in renewable energy. But it should not simply be assumed that renewable resources require flexible resources to offset their output fluctuations. PJM markets should provide incentives, especially in the capacity market, for renewable resources to provide higher quality capacity and more stable output by creating hybrid resources. For example, if the ELCC calculations reflected the relatively low marginal value of standalone renewables, as they should, and the significantly higher marginal value of hybrids, there would be a strong incentive to combine resources into hybrids. There would be a related incentive to invest in longer duration hybrids over shorter duration hybrids. PJM does not need a flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists and to stop creating incentives for inflexibility. This means enforcing parameter limited schedules, enforcing must offer requirements, enhancing generator modelling to support combined cycle resources, and requiring resources to follow PJM's dispatch instructions in order to be eligible for uplift payments. There is no reason to consider a new flexibility product until the existing rules are enforced and refined, including the elimination of current incentives to be inflexible.

PJM interventions in the market have substantial effects on energy market outcomes. For example, transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create significant price increases through transmission line limit violations or restrictions on the resources available to resolve constraints. PJM interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. In 2021, 7.2 percent of the total load-weighted LMP was the result of the transmission constraint violation penalty factors. PJM reduced transmission line ratings in almost all of these cases, increasing the number and impact of such penalties. PJM also increased the constraint penalty factor from $2,000 per MWh to $3,000 per MWh in some cases, for reasons that are not clear. PJM should limit its interventions in the market and provide greater transparency about the reasons and impacts, if any such interventions continue, in order to enhance market efficiency.

Fast start pricing significantly increases energy market prices in ways not consistent with competitive markets. Fast start pricing, implemented on September 1, 2021, creates an inefficient wedge between the competitive price and the actual price paid to generators and charged to customers. Fast start pricing increased average real-time energy market prices by 5.5 percent. This is a significant increase to energy prices given that it does not result from any change to the underlying market supply and demand fundamentals.

Changes to the operating reserve demand curve (ORDC), previously approved by FERC and planned for implementation in 2022, were reversed by the Commission in an order issued on December 22, 2021. The changes, if implemented, would have increased the price for reserve quantities less than the reserve requirement to $2,000 per MWh, and prices beyond the reserve requirement to levels that were based on an extended downward sloping ORDC, and the price cap would have been removed. The MMU had opposed those changes. While Commission's order maintains the current levels of emergency pricing, rather than PJM's higher proposed levels, there remain possible scenarios in which prolonged and excessively high administrative pricing in the energy market under the current tariff provisions would impose inefficient wealth transfers. Inefficient wealth transfers from load to generation, among generators, or from physical to financial market participants occur when administrative pricing creates arbitrarily high price signals to which participants cannot respond. While appropriate shortage pricing is important, there is no demonstrated benefit to imposing extreme prices for either long term generation incentives to invest in reliable capacity or customer incentives to curtail usage during an emergency.

On September 29, 2021, PJM's filing to revise the Minimum Offer Price Rule (MOPR) was made effective by operation of law. The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.

The competitiveness of energy market prices cannot be taken for granted. Despite low average marginal unit markups in 2021, 4.7 percent of marginal units set price with positive markups, in some cases over $150 per MWh, despite failing the Three Pivotal Supplier (TPS) test for market power in the real-time energy market. This was the result of documented flaws in the application of offer capping when units fail the TPS test. PJM also schedules and pays uplift to units that fail the TPS test without requiring that units use flexible operating parameters, an issue that FERC raised in a June 17, 2021, Order to Show Cause. In addition to the existing issues with market power mitigation, the definition of a competitive energy offer is overstated through the inclusion of major maintenance costs which do not vary in the short run with energy output and are not short run marginal costs. Further, the use of and applicability of fuel cost policies have been undermined. Fuel cost policies ensure that the costs in generator offers are clearly defined and are verifiable and systematic. Fuel cost policies are required for effective and accurate market power mitigation. Some generation owners prefer to not have clearly defined costs in order to exercise market power and in order to avoid taking responsibility for the accuracy of their offers.

If PJM markets are going to continue to be sustainable, it is essential that the basic structure of the current capacity market remain, including the single definition of reliability for the PJM market, the incorporation of transmission constraints and locational supply and demand fundamentals, and a clear definition of capacity and the contribution of capacity to reliability. The basic structure of the capacity market includes a must offer and a must buy requirement that are essential and have been demonstrated to be essential to limiting market power and operating a competitive market. The PJM Capacity Market has never been nor was it ever intended to be a residual market, as evidenced by the must buy and must sell provisions of the market rules. Reliability is only definable at the level of the entire PJM market, including locational differences based on transmission constraints. The market reflects the interactions across free flowing ties throughout the entire network. There are transmission constraints that prevent the lowest cost capacity from providing reliability in constrained areas. Locational prices reflect the combination of transmission constraints and local supply and demand conditions.

Purely bilateral markets are characterized by a lack of transparency, a corresponding asymmetry in access to information that favors market sellers, and the resultant ability of sellers to exercise market power. Transparent clearing markets are the best way to facilitate bilateral contracts. PJM had only a bilateral capacity market at its inception. That bilateral market was replaced in 1999, at the request of the Pennsylvania Public Utility Commission, by PJM's first transparent, mandatory capacity clearing market, the precursor to the current design. The problem with the bilateral market was that reliance on voluntary bilateral sales and purchases facilitated the exercise of market power by incumbents and served as a barrier to entry to retail competitors, because the new entrant had to purchase capacity from the utilities with which it was competing for retail load.

It is also essential that the contribution of different types of capacity be calculated in a comparable manner. The contribution of one MW of a solar or wind resource is not the same as the contribution of one MW of a gas fired combined cycle resource. Capacity must be defined in a homogeneous manner so that the clearing price is the same for all MW of capacity that provide the same contribution to reliability. Capacity should be offered and cleared in the capacity market only at a MW level that reflects its contribution to reliability. For most wind and solar resources that means a capacity value appropriately derated from the nameplate capability.

In order for the capacity market to provide competitive price signals, particularly with more renewable and intermittent resources, the ELCC values must be accurate. PJM has replaced default derating factors by technology type with the Effective Load Carrying Capability (ELCC) approach. PJM's approach to calculating ELCC values by technology is badly flawed. Fixing the PJM approach to ELCC is a manageable task if there is a shared goal of letting markets reflect the actual, marginal contribution of all types of capacity (including fossil resources) to reliability without assumptions that arbitrarily favor some resource types.

Derating factors and ELCC values are used in capacity auctions to convert the nameplate capacity of intermittent and storage resources into MW of capacity equivalent to resources that can produce for any of the 8,760 hours in a year. Both the capacity derating factors applied to intermittent nameplate capacity in the 2022/2023 BRA and the ELCC calculations to be used for future capacity auctions are based on the assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity. The definition of intermittent capacity is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. Intermittent resources, including storage, should not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs).

Renewable energy was a relatively small share of PJM total energy and capacity in 2021 but many renewable projects are under development. While renewables currently make up the majority of both projects and nameplate MW in the interconnection queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables and by thermal resources. Of the 18,707.9 MW of combined cycle projects in the queue, 11,128.3 MW (59.5 percent) are expected to go in service based on historical completion rates as of December 31, 2021, providing both energy and capacity at that level. Of the 191,372.4 MW of renewable projects in the queue, only 24,300.6 MW (12.7 percent) are expected to go in service based on historical completion rates and be available to supply energy. Of those 24,300.6 MW, only 9,871.6 MW (5.1 percent of the total) are expected to be capacity resources, based on the average derate factors for wind and solar.

PJM has regularly procured excess capacity in excess of the reserve requirement at significant cost to customers, both as a result of over forecasted demand and the shape and location of the capacity market demand (VRR) curve. But the quality and significance of PJM reserves needs to be analyzed carefully.

The level of cleared demand resources (8,710.3 MW) is greater than the entire level of excess capacity cleared in the auction (7,660.2 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called. If DR were part of the required reserves and there were no excess capacity, the probability of PAI would increase, potentially significantly.

In addition, the sum of cleared MW that were considered categorically exempt from the capacity market must offer requirement is 8,113.0 MW, or 48.5 percent of the required reserves and 33.3 percent of total reserves. The sum of cleared MW that did not have a must offer requirement and the cleared MW of DR is 16,823.3 MW, or 100.7 percent of required reserves and 69.0 percent of total reserves.

These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.

The evolution of wholesale power markets is far from complete. The market design can be improved and made more efficient and more competitive. PJM and its market participants will need to continue to work constructively to refine the competitive market design and to ensure the continued effectiveness of PJM markets in providing customers wholesale power at the lowest possible price, but no lower.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM market summary statistics: 2020 and 2021[1]

	2020	2021	Percent Change
Average Hourly Load Plus Exports (MW)	90,059	92,774	3.0%
Average Hourly Generation Plus Imports (MW)	91,674	94,501	3.1%
Peak Load (MW)	148,996	151,680	1.8%
Installed Capacity at December 31 (MW)	184,237	186,593	1.3%
Load Weighted Average Real Time LMP ($/MWh)	$21.77	$39.78	82.8%
Total Congestion Costs ($ Million)	$528.7	$995.3	88.3%
Total Uplift Credits ($ Million)	$90.9	$178.3	96.1%
Total PJM Billing ($ Billion)	$36.28	$54.13	49.2%

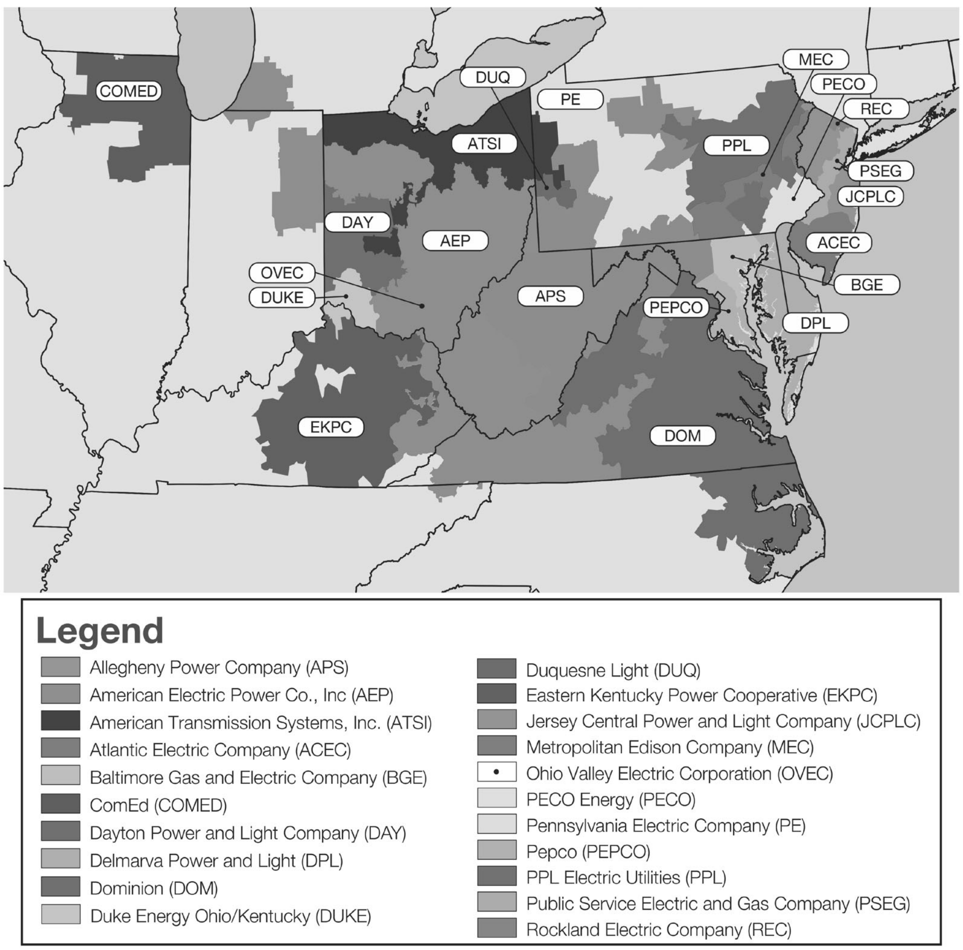
1 In Table 1-1, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2021, had installed generating capacity of 186,593 megawatts (MW) and 1,045 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia (Figure 1-1).[2 3 4]

As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

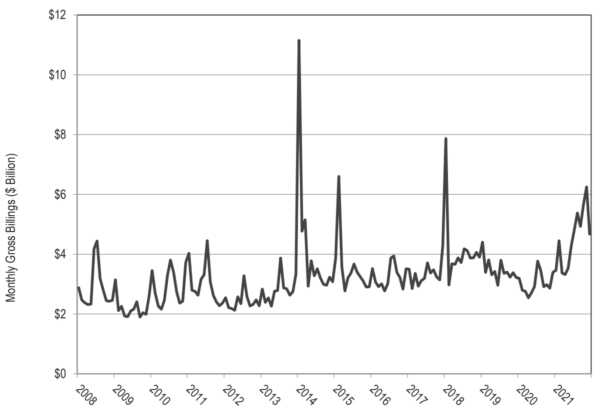
Figure 1-1 PJM's footprint and its 21 control zones



2 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2021 State of the Market Report for PJM*, Volume II, Appendix A: "PJM Overview" for maps showing the PJM footprint and its evolution prior to 2021.

In 2021, PJM had net gross billings of $54.13 billion, an increase of 49.2 percent from $36.28 billion in 2020, and the largest annual billing since 2014. (Figure 1-2).[5]

Figure 1-2 PJM reported monthly billings ($ Billion): 2008 through 2021[6]



PJM operates the day-ahead energy market, the real-time energy market, the Reliability Pricing Model (RPM) capacity market, the regulation market, the synchronized reserve market, the day-ahead scheduling reserve (DASR) market and the financial transmission rights (FTRs) markets.

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented FTRs on May 1, 1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM modified the regulation market design and added a market in Synchronized Reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM capacity market effective June 1, 2007. PJM implemented the DASR market on June 1, 2008. PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.[7] [8]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2021, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

For each PJM market, the market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the cost, demand, and ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for the ownership of assets and the relationship among the pattern of ownership, the resource costs, and the market demand using actual market conditions with both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referred to as participant conduct.

5 The MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process..

6 In Figure 1-2, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

7 See also the *2021 State of the Market Report for PJM*, Volume II, Appendix A: "PJM Overview."

8 Analysis of 2021 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DUQ) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DUKE) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2020, see *2019 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Overview."

Market performance refers to the outcomes of the market. Market performance results from the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of short run marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market outcomes, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

Energy Market Conclusion

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in 2021.

Table 1-2 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in 2021 was, on average, unconcentrated by FERC HHI standards. Average HHI was 742 with a minimum of 532 and a maximum of 1115 in 2021. The intermediate segment was moderately concentrated. The peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to require competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.

- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market. PJM resolved the problems with real-time dispatch and pricing on November 1, 2021. The implementation of fast start pricing on September 1, 2021 undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.[9] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[10] In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[11] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. FERC recognized these issues in its June 17, 2021 order.[12] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

Capacity Market Conclusion

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices,

9 OATT Attachment M (PJM Market Monitoring Plan).

10 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).

11 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

12 175 FERC ¶ 61,231 (2021).

outage rates and reliability.[13] The conclusions are a result of the MMU's evaluation of the 2022/2023 Base Residual Auction.

Table 1-3 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[14] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[15]
- Participant behavior was evaluated as not competitive in the 2022/2023 RPM Base Residual Auction. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the Net CONE times B offer cap under the capacity performance design exceeds the competitive level. In the 2022/2023 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30, and the other strong CP assumptions are also not correct. Under these circumstances, a competitive offer is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions. The Commission recognized this issue and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021. But the 2022/2023 BRA was conducted with the previous default MSOC of Net CONE times B.[16]
- Market performance was evaluated as not competitive based on the 2022/2023 RPM Base Residual Auction. Although structural market power exists in the capacity market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2022/2023 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.
- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2021, and for a number of additional reasons, the 2023/2024 Base Residual Auction is delayed and scheduled for June 2022, and first and second incremental auctions for the 2022/2023 through 2026/2027 Delivery Years are canceled if within 10 months of the revised BRA schedule.[17]

13 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

14 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.

15 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

16 176 FERC ¶ 61,137 (September 2, 2021).

17 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021).

Tier 2 Synchronized Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for 2021.

Table 1-4 The tier 2 synchronized reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require cost-based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately overcompensated when the nonsynchronized reserve market clears with a nonzero price.

Day-Ahead Scheduling Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM DASR Market for 2021.

Table 1-5 The day-ahead scheduling reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Mixed	
Market Performance	**Competitive**	**Mixed**

- The DASR market structure was evaluated as not competitive because the DASR market failed the three pivotal supplier (TPS) test in 94 percent of the intervals in which the price was greater than $0.01 per MWh.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. The day-ahead scheduling reserve market clearing price was above $0 in 16.9 percent of hours in 2021. In 98.6 percent of hours when the clearing price was above $0, the clearing price was the offer price of the marginal unit. In the remaining 1.4 percent of hours, the price included lost opportunity cost.
- Market design was evaluated as mixed because the DASR product does not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised.

Regulation Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for 2021.

Table 1-6 The regulation market results were not competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 85.9 percent of the hours in 2021.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in 2021 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin raises questions.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in

optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

FTR Auction Market Conclusion

The *2021 State of the Market Report for PJM* focuses on the 2020/2021 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2021, through December 31, 2021. The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were partially competitive in 2021.

Table 1-7 The FTR auction markets results were partially competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Partially Competitive	
Market Performance	**Partially Competitive**	**Flawed**

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2021/2024 Long Term FTR Auction, the 2021/2022 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 2020/2021 Annual FTR Auction. Ownership of FTRs is disproportionately (76.2 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs are not permitted to participate in the market clearing.
- Market performance was evaluated as partially competitive because of the flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that sellers are required to return some of the cleared auction revenue to FTR buyers when FTR profits are not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Role of MMU

FERC assigns three core functions to MMUs: reporting, monitoring and market design.[18] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant;

18 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[19]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market issues, such as RPM auction reports; reports responding to requests from regulators and other authorities; and ad hoc reports on specific topics. The state of the market reports provide a comprehensive analysis of market structure, participant conduct and market performance for the PJM markets. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU presents reports directly to PJM stakeholders, PJM staff, FERC staff, state commission staff, state commissions, other regulatory agencies and the general public. Report presentations provide an opportunity for interested parties to ask questions, discuss issues, and provide feedback to the MMU.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[20] The MMU has direct, confidential access to FERC.[21] The MMU may also refer matters to the attention of state commissions.[22]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[23] The MMU will investigate and refer "Market Violations," which refer to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[24] [25] [26] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[27]

An important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price-based or cost-based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost-based offer accurately reflects short run marginal cost.

If cost-based offers do not accurately reflect short run marginal cost, the market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[28]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with

19 OATT Attachment M § IV; 18 CFR § 1c.2.
20 OATT Attachment M § IV.
21 OATT Attachment M § IV.K.3.
22 OATT Attachment M § IV.H.
23 OATT § I.1 ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")
24 FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
25 OATT § I.1.
26 The MMU has no prosecutorial or enforcement authority. The MMU notifies FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to FERC, state regulators, stakeholders or other authorities. The MMU may also initiate, participate as a party or provide information or testimony in regulatory or other proceedings.
27 OATT Attachment M § IV.C.
28 OATT Attachment M–Appendix § II.E.

the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the day-ahead and real-time energy markets.[29] [30] [31] [32]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns. Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with FERC or other regulatory authorities. FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

The PJM markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[33] [34]

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[35]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[36] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[37] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design, market rules and market rule implementation issues, including complaints or petitions.[38] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[39] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[40]

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[41]

In this *2021 State of the Market Report for PJM*, the MMU includes 20 new recommendations made for 2021, 13 of which are new in this 2021 annual report.[42] [43]

New Recommendations from Section 3, Energy Market

- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends, if PJM implements extended downward sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on ten minute rather than 30 minute forecast error, and on forced outages in the ten minute rather than the 30 minute

29 OATT Attachment M–Appendix § II.B.
30 OATT Attachment M–Appendix § II.C.
31 OATT Attachment M–Appendix § IV.
32 OATT Attachment M–Appendix § VII.
33 OATT Attachment M–Appendix § II(p).
34 OATT Attachment M–Appendix § III.
35 OA Schedule 6 § 1.5.
36 OATT Attachment M § IV.D.
37 *Id.*
38 *Id.*; see also, e.g., 171 FERC ¶ 61,039; 167 FERC ¶ 61,084 at PP 70–76, *reh'g denied*, 168 FERC ¶ 61,141.
39 *Id.*
40 OATT Attachment M § VI.A.
41 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
42 New recommendations include all MMU recommendations that were reported for the first time in the *2021 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2021.
43 For a complete list of MMU recommendations, see the *2021 State of the Market Report for PJM*, Vol II, Section 2, Recommendations.

look ahead window to model the uncertainty in the inputs to RT SCED. (Priority: Medium. First reported Q2, 2021. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3, 2021. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 4, Energy Uplift

- The MMU recommends that units not be paid lost opportunity cost uplift when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported Q2, 2021. Status: Not adopted.)

New Recommendations from Section 5, Capacity Market

- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported Q3, 2021. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and storage resources, including hydro. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 6, Demand Response

- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 8, Environmental and Renewable Regulations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. Status: Not adopted.)[44]

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)

New Recommendation from Section 13, Financial Transmission Rights and Auction Revenue Rights

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. New recommendation. Status: Not adopted.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of wholesale electricity in PJM markets.[45] The total price is an average price. Prices vary by location and time period. The total price includes the price of energy, capacity, transmission service, ancillary services, and administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for 2020 and 2021.

The total costs for each year shown in Table 1-8 equal the total price per MWh, by category, multiplied by the total load. The total costs are different from the total billing values that PJM reports as shown in Figure 1-2. PJM's reported total billing values represent the total dollars that pass through the PJM settlement process.

Each of the components in Table 1-8 is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real-time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration

44 This recommendation was first reported in 2010, but has been enhanced in the *2021 State of the Market Report for PJM.*

45 Accounting load is used in the calculation of total price because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the incorporation of marginal loss pricing in LMP.

charges, and firm and nonfirm point to point transmission service.[46]

- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[47]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[48]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[49]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI, CAPS and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[50]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[51]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[52]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the day-ahead scheduling reserve market.[53]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[54]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[55]
- The Black Start component is the average cost per MWh of black start service.[56]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[57]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[58]
- The Economic Load Response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.[59]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[60]
- The Nonsynchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[61]
- The Emergency Energy component is the average cost per MWh of emergency energy.[62]

46 OATT §§ 13.7, 14.5, 27A & 34.
47 OA Schedules 1 §§ 3.2.3 & 3.3.3.
48 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
49 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
50 OATT Schedule 12.
51 RAA Schedule 8.1.
52 OATT PJM Emergency Load Response Program.
53 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
54 OATT Schedule 1A.
55 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
56 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.
57 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
58 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
59 OA Schedule 1 § 3.6.
60 OA Schedule 1 § 5.3b.
61 OA Schedule 1 § 3.2.3A.001.
62 OA Schedule 1 § 3.2.6.

Table 1-8 shows that energy, capacity and transmission charges are the three largest components of the total price per MWh of wholesale power, comprising 97.5 percent of the total price per MWh in 2021. The total price per MWh of wholesale power increased from $44.59 in 2020 to $65.14 in 2021, an increase of 46.1 percent. Starting in the third quarter of 2019, for the first time since the start of the PJM RPM Capacity Market in 2007, the cost of transmission has been a larger share of the total price per MWh of wholesale power than the cost of capacity.

Table 1-8 Total price per MWh by category: 2020 and 2021[63 64 65]

Category	2020 $/MWh	2020 ($ Millions)	2020 Percent of Total	2021 $/MWh	2021 ($ Millions)	2021 Percent of Total	Percent Change
Load Weighted Energy	$21.77	$16,171	48.8%	$39.78	$30,532	61.1%	82.8%
Capacity	$9.45	$7,023	21.2%	$10.96	$8,408	16.8%	15.9%
Capacity	$9.45	$7,023	21.2%	$10.95	$8,406	16.8%	15.9%
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$2	0.0%	0.0%
Capacity (RMR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission	$12.01	$8,923	26.9%	$12.76	$9,789	19.6%	6.2%
Transmission Service Charges	$11.32	$8,412	25.4%	$12.08	$9,268	18.5%	6.7%
Transmission Enhancement Cost Recovery	$0.59	$441	1.3%	$0.59	$450	0.9%	(1.3%)
Transmission Owner (Schedule 1A)	$0.09	$69	0.2%	$0.09	$71	0.1%	(0.9%)
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.72	$537	1.6%	$0.87	$669	1.3%	20.7%
Reactive	$0.47	$348	1.0%	$0.48	$371	0.7%	3.3%
Regulation	$0.10	$77	0.2%	$0.19	$145	0.3%	81.9%
Black Start	$0.09	$65	0.2%	$0.09	$68	0.1%	1.8%
Synchronized Reserves	$0.03	$25	0.1%	$0.08	$58	0.1%	120.2%
Non-Synchronized Reserves	$0.01	$8	0.0%	$0.02	$17	0.0%	99.1%
Day Ahead Scheduling Reserve (DASR)	$0.02	$13	0.0%	$0.01	$10	0.0%	(28.2%)
Administration	$0.52	$384	1.2%	$0.54	$416	0.8%	4.8%
PJM Administrative Fees	$0.48	$355	1.1%	$0.51	$388	0.8%	5.6%
NERC/RFC	$0.04	$28	0.1%	$0.04	$28	0.1%	(2.4%)
RTO Startup and Expansion	$0.00	$1	0.0%	$0.00	$0	0.0%	(100.0%)
Energy Uplift (Operating Reserves)	$0.12	$90	0.3%	$0.23	$178	0.4%	90.1%
Demand Response	$0.00	$1	0.0%	$0.00	$1	0.0%	14.3%
Load Response	$0.00	$1	0.0%	$0.00	$1	0.0%	14.3%
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$44.59	$33,130	100.0%	$65.14	$49,992	100.0%	46.1%
Total Load (GWh)	742,987			767,425			3.3%
Total Cost ($ Billions)	$33.13			$49.99			50.9%

63 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
64 The total cost in this table does not match the PJM reported total billing due to differences in calculation methods. The total prices in this table are load weighted average system prices per MWh by category, even if each category is not charged on a per MWh basis. PJM's reported total billing represents the total dollars that pass through the PJM settlement process.
65 The MMU publishes monthly detail of these components of PJM price. See <http://www.monitoringanalytics.com/data/pjm_price.shtml>.

Table 1-9 shows the inflation adjusted average price, by component, for 2020 and 2021. To calculate the inflation adjusted average prices, the individual components' prices are deflated using the US Consumer Price Index for all items, Urban Consumers (with a base period of January 1998).[66]

Table 1-9 Inflation adjusted total price per MWh by category: 2020 and 2021[67]

Category	2020 $/MWh	2020 ($ Millions)	2020 Percent of Total	2021 $/MWh	2021 ($ Millions)	2021 Percent of Total	Percent Change
Load Weighted Energy	$13.58	$10,091	48.8%	$23.63	$18,137	61.0%	74.0%
Capacity	$5.90	$4,385	21.2%	$6.52	$5,003	16.8%	10.4%
Capacity	$5.90	$4,385	21.2%	$6.52	$5,002	16.8%	10.4%
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$1	0.0%	0.0%
Capacity (RMR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission	$7.50	$5,572	26.9%	$7.61	$5,839	19.6%	1.5%
Transmission Service Charges	$7.07	$5,253	25.4%	$7.20	$5,528	18.6%	1.9%
Transmission Enhancement Cost Recovery	$0.37	$276	1.3%	$0.35	$268	0.9%	(5.7%)
Transmission Owner (Schedule 1A)	$0.06	$43	0.2%	$0.06	$42	0.1%	(5.2%)
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.45	$335	1.6%	$0.52	$398	1.3%	15.1%
Reactive	$0.29	$217	1.0%	$0.29	$221	0.7%	(1.3%)
Regulation	$0.06	$48	0.2%	$0.11	$86	0.3%	72.9%
Black Start	$0.05	$41	0.2%	$0.05	$41	0.1%	(2.9%)
Synchronized Reserves	$0.02	$16	0.1%	$0.04	$34	0.1%	109.4%
Non-Synchronized Reserves	$0.01	$5	0.0%	$0.01	$10	0.0%	88.4%
Day Ahead Scheduling Reserve (DASR)	$0.01	$8	0.0%	$0.01	$6	0.0%	(31.8%)
Administration	$0.32	$240	1.2%	$0.32	$249	0.8%	0.2%
PJM Administrative Fees	$0.30	$222	1.1%	$0.30	$232	0.8%	1.1%
NERC/RFC	$0.02	$17	0.1%	$0.02	$17	0.1%	(6.8%)
RTO Startup and Expansion	$0.00	$1	0.0%	$0.00	$0	0.0%	(100.0%)
Energy Uplift (Operating Reserves)	$0.08	$56	0.3%	$0.14	$106	0.4%	81.6%
Demand Response	$0.00	$1	0.0%	$0.00	$1	0.0%	0.0%
Load Response	$0.00	$1	0.0%	$0.00	$1	0.0%	0.0%
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$27.83	$20,680	100.0%	$38.74	$29,731	100.0%	39.2%
Total Load (GWh)	742,987			767,425			3.3%
Total Cost ($ Billions)	$20.68			$29.73			43.8%

66 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 12, 2022).

67 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-3 shows the contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.

Figure 1-3 Top three components of quarterly total price ($/MWh): January 1999 through December 2021[68]

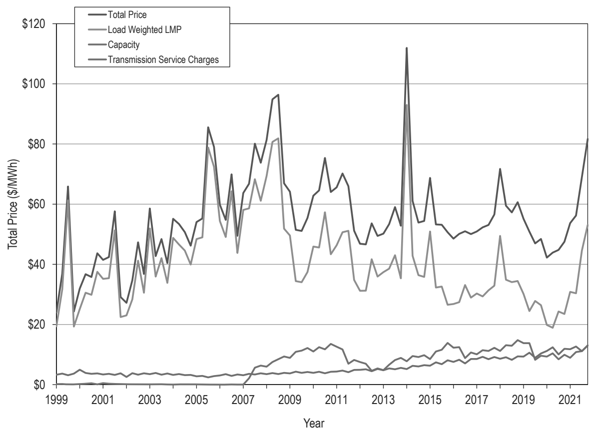


Figure 1-4 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[69]

Figure 1-4 Inflation adjusted top three components of quarterly total price ($/MWh): January 1999 through December 2021[70]

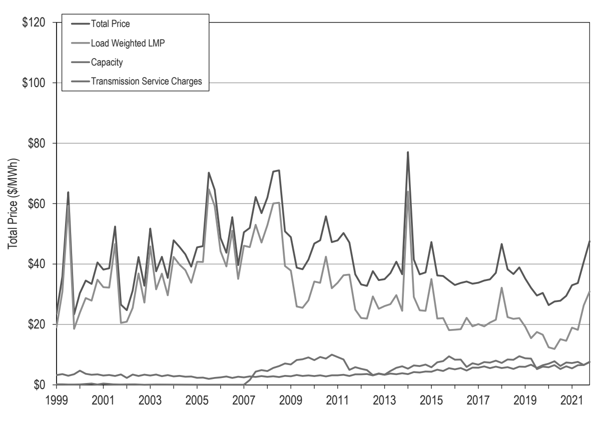
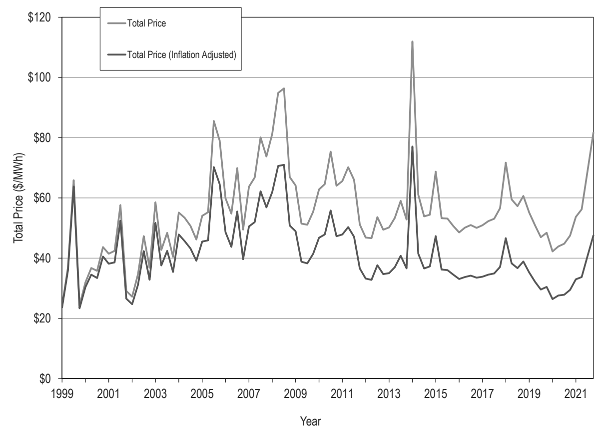


Figure 1-5 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 1999.[71]

Figure 1-5 Quarterly total price and quarterly inflation adjusted total price ($/MWh): January 1999 through December 2021[72]



Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

- **Supply.** In 2021, 3,990 MW of new resources were added in the energy market, and 1,308 MW of resources were retired.

  The real-time hourly on peak average offered supply was 139,027 MW in 2020, and 136,184 MW in 2021. The day-ahead hourly on peak average offered supply was 158,253 MW in 2020, and 155,811 MW in 2021.

  The real-time hourly average cleared generation in 2021 increased by 3.0 percent from 2020, from 90,938 MWh to 93,644 MWh.

  The day-ahead hourly average supply in 2021, including INCs and UTCs, decreased by 8.1 percent from 2020, from 111,470 MWh to 102,431 MWh.

68 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

69 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 12, 2022).

70 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

71 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 12, 2022).

72 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

- **Demand.** The real-time hourly peak load plus exports in 2021 was 151,680 MWh (145,561 MWh of load plus 6,120 MWh of gross exports) in the HE 1800 on August 24, 2021, which was 1.8 percent, 2,684 MWh, higher than the PJM peak load plus exports in 2020, which was 148,996 MWh in the HE 1800 on July 20, 2020.

  The real-time hourly average load in 2021 increased by 3.6 percent from 2020, from 84,584 MWh to 87,606 MWh.

  The day-ahead hourly average demand in 2021, including DECs and UTCs, decreased by 8.2 percent from 2020, from 106,209 MWh to 97,537 MWh.

Market Behavior

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW decreased by 12.1 percent and cleared MW decreased by 4.5 percent in 2021 compared to 2020. The hourly average submitted decrement bid MW increased by 12.0 percent and cleared MW decreased by 2.4 percent in 2021 compared to 2020. The hourly average submitted up to congestion bid MW decreased by 58.2 percent and cleared MW decreased by 61.4 percent in 2021 compared to 2020.

Market Performance

- **Generation Fuel Mix.** In 2021, generation from coal units increased 17.8 percent, generation from natural gas units decreased 2.3 percent, and generation from oil increased 11.5 percent compared to 2020. Wind and solar output rose by 15.7 percent compared to 2020, supplying 4.2 percent of PJM energy in 2021.

- **Fuel Diversity.** The fuel diversity of energy generation in 2021, measured by the fuel diversity index for energy (FDI_e), increased 1.8 percent compared to 2020.

- **Marginal Resources.** In the PJM Real-Time Energy Market in 2021, coal units were 14.1 percent and natural gas units were 71.7 percent of marginal resources. In 2020, coal units were 17.5 percent and natural gas units were 72.6 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in 2021, UTCs were 35.2 percent, INCs were 17.9 percent, DECs were 27.1 percent, and generation resources were 19.5 percent of marginal resources. In 2020, UTCs were 51.4 percent, INCs were 13.2 percent, DECs were 18.8 percent, and generation resources were 16.5 percent of marginal resources.

- **Prices.** The real-time load-weighted average LMP in 2021 increased 82.8 percent from 2020, from $21.77 per MWh to $39.78 per MWh.

  The day-ahead load-weighted average LMP in 2021 increased 84.0 percent from 2020, from $21.40 per MWh to $39.37 per MWh.

- **Fast Start Pricing.** The real-time load-weighted average PLMP was $52.20 per MWh for September 1, 2021, through December 31, 2021, which is 5.5 percent, $2.73 per MWh, higher than the real-time load-weighted average DLMP of $49.47 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market in 2021, 10.2 percent of the load-weighted LMP was the result of coal costs, 53.9 percent was the result of gas costs and 3.2 percent was the result of the cost of emission allowances. In 2021, 8.3 percent of load-weighted LMP was the result of the transmission constraint violation penalty factor due to an increased frequency of transmission constraint violations, especially on the 500 kV system. PJM implemented Fast Start Pricing on September 1, 2021, which explicitly allowed commitment costs to affect LMPs. In the first four months of the fast start pricing in PJM, 3.4 percent of the real-time load-weighted average LMP was the result of commitment costs.

  In the PJM Day-Ahead Energy Market in 2021, 25.9 percent of the load-weighted LMP was the result of gas costs, 11.2 percent was the result of coal costs, 29.7 percent was the result of DEC bids, 17.2 percent was the result of INC offers, 5.7 percent was the result of positive markup, and 0.8 percent was the result of UTCs. In the first four months of fast start pricing in PJM, 0.4 percent of the day-ahead load-weighted average LMP was the result of commitment costs.

- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The difference between day-ahead and real-time average prices was $0.42 per MWh in 2021, and $0.33 per MWh in 2020. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were 28 intervals with five minute shortage pricing in 2021. There were no emergency actions that resulted in Performance Assessment Intervals in 2021.
- There were 5,590 five minute intervals, or 5.3 percent of all five minute intervals, in 2021 for which at least one RT SCED solution showed a shortage of reserves, and 1,572 five minute intervals, or 1.5 percent of all five minute intervals, in 2021 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for 28 five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Three suppliers were jointly pivotal in the day-ahead market on 301 days in 2020 and 286 days in 2021.
- **Local Market Power.** In 2021, 11 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. For three out of the top 10 congested facilities (by real-time binding hours) in 2021, the average number of suppliers providing constraint relief was three or less. There is a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure is not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 1.6 percent in 2020 and 2021. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.0 percent in 2020 to 1.5 percent in 2021. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

  The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in 2020 to 0.02 percent in 2021. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in 2020 to 0.03 percent in 2021. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based

offer for commitment even if it has less flexible operating parameters.

- **Parameter Mitigation.** In 2021, 28.0 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. In 2021, on days when hot weather and cold weather alerts were declared, 32.6 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder, in January.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -0.01 in 2021, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in 2021 was more than $450 per MWh when using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was 0.07 in 2021, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in 2021 was more than $140 per MWh when using unadjusted cost-based offers.
- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Market Performance

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

  In the PJM Real-Time Energy Market in 2021, the unadjusted markup component of LMP was $1.69 per MWh or 4.2 percent of the PJM load-weighted average LMP. August had the highest unadjusted peak markup component, $6.68 per MWh, or 11.8 percent of the real-time peak hour load-weighted average LMP for August.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2021, the unadjusted markup component of LMP was $1.22 per MWh or 3.1 percent of the PJM day-ahead load-weighted average LMP. October had the highest unadjusted peak markup component, $8.06 per MWh, or 12.0 percent of the day-ahead peak hour load-weighted average LMP for October.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.
- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 4.7 percent of all real-time marginal unit intervals in 2021, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.
- **Markup and Aggregate Market Power.** In 2021, pivotal suppliers in the aggregate market set prices with high markups for some real-time market intervals.

Section 3 Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3 2021. Status: Not adopted.)
- The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the

TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based

offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)

- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. New recommendation. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Adopted 2021.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[73] [74] (Priority: Low. First reported 2013. Status: Not adopted.)

73 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

74 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends, if PJM implements extended downward sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on ten minute rather than 30 minute forecast error, and on forced outages in the ten minute rather than the 30 minute look ahead window to model the uncertainty in the inputs to RT SCED. (Priority: Medium. First reported Q2, 2021. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. New recommendation. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)

- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2021, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

PJM real-time hourly average load in 2021 increased by 3.6 percent from 2020, from 84,584 MWh to 87,606 MWh. The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[75] However, there are some issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021.[76] PJM continues to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[77] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021, and continues to recommend them.[78]

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs. This rule also had unintended consequences for market seller offer caps in the capacity market. Maintenance costs includable in energy offers cannot be included in capacity market offer caps based on avoidable costs. As a result, capacity market offer caps based on net avoidable costs were lower than they would have been if maintenance costs had been correctly included in avoidable costs rather than incorrectly defined to be part of short marginal

75 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
76 See 175 FERC ¶ 61,231 (2021).
77 *See* PJM. "Answer of PJM Interconnection L.L.C.," Docket No. EL21-78 (September 15, 2021).
78 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).

costs of producing energy and includable in energy offers.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market. In a competitive market, prices are directly related to the marginal cost to serve load at a given time. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2021 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel, staff their units, and operate rather than economically withhold or physically withhold.

Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices were a primary cause of low PJM energy market prices from 2017 to 2020. Higher natural gas prices are a primary cause of higher prices in 2021. There is no evidence to support significant changes to the calculation of LMP, such as fast start pricing or the extended ORDC. Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The extended ORDCs would have created shortage pricing when no reserve shortages exist and, in emergency situations, would have resulted in unjustifiable wealth transfers due to extreme high pricing with no demonstrable market benefit. These changes are unnecessary and distort, rather than improve, price formation. PJM appropriately and directly addressed price formation with the changes that went into effect on November 1, 2021, to resolve the timing mismatch between pricing (LPC) and dispatch instructions (RT SCED). Other potential areas for improvements in price formation include shortage pricing, operator actions and the design of reserve markets. FERC's December 22, 2021, order reversed its prior approval of PJM's proposed extended ORDCs, but accepted other changes to the reserve market design, including the consolidation of tier 1 and tier 2 synchronized reserves and the addition of a day-ahead reserve market. The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to addressed.[79] There are also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels (the current triggers are based on estimates that result from inaccurate generator modeling, and PJM's administrative overrides on eligibility of units to provide reserves) and the lack of adequate locational scarcity pricing options.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission line limit violations. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modified the values offered by generators and limits the MW available to the RT SCED through the first 10 months of 2021.[80] Rather than sending dispatch signals consistent with resource offers and holding resources accountable when they fail to follow them, DGP accommodated resources that did not follow dispatch. PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[81] The tradeoff exists because when commitment costs are included in prices,

79 177 FERC ¶ 61,209 (2021).
80 DGP in the calculation of energy dispatch was removed as of November 1, 2021.
81 See 173 FERC ¶ 61,244 (2020).

the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders.

Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing. While the magnitude of the new payments was small in 2021, their effects on behavior are not clear yet.

PJM's arguments for changing energy market price formation asserted that fast start pricing and the extended ORDC would price flexibility in the market, but instead they will benefit inflexible units. The fast start pricing and extended ORDC solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units, for investment in increased flexibility of existing units, and for operating at the full extent of existing flexibility should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised and ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would have done, is not scarcity pricing but simply a revenue enhancement mechanism, which could have unintended consequences in an emergency, as was the case in ERCOT in February 2021. The Commission recognized that PJM's ORDC changes were not consistent with efficient market design and were just a revenue enhancement mechanism.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in 2021 or prior years. In 2021, marginal units were predominantly combined cycle gas generators. The frequency of combined cycle gas units as the marginal unit type has risen rapidly, from 31.2 percent in 2016 to 71.7 percent in 2021. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units have placed competitive pressure on less efficient generators, and the market has reliably served load with less congestion, less uplift, and less markup as a result. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in 2021.

Overview: Section 4, Energy Uplift

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $87.4 million, or 96.2 percent, in 2021 compared to 2020, from $90.9 million to $178.3 million.
- **Energy Uplift Charges Categories.** The increase of $87.4 million in 2021 was comprised of a $4.4 million increase in day-ahead operating reserve charges, an $82.5 million increase in balancing operating reserve charges, and a $0.5 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.016 per MWh in the Eastern Region. Real-time load and exports paid $0.084 per MWh. Deviations (which include deviations from load, imports, exports, generators, INCs, DECs and UTCs) paid $0.467 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid $ 0.210 per MWh in the Western Region. Real-time load and exports paid $0.073 per MWh. Deviations (which include deviations from load, imports, exports, generators, INCs, DECs and UTCs) paid $0.416 per MWh in the Western Region.
- **Reactive Services Rates.** PPL and COMED were the two zones with the highest local reactive services (voltage support) rates, excluding reactive capability payments. PPL had a rate of $0.017 per MWh and COMED had a rate of $0.002 per MWh.

Energy Uplift Credits

- **Types of credits.** In 2021, energy uplift credits were $178.3 million, including $13.7 million in day-ahead generator credits, $127.5 million in balancing generator credits, $30.3 million in lost opportunity cost credits, and $4.8 million in local constraint control credits. Dispatch differential lost opportunity credits, implemented as part of fast start pricing on September 1, 2021, were $0.7 million.
- **Types of units.** In 2021, coal units received 72.0 percent of day-ahead generator credits, and combustion turbines received 92.8 percent of balancing generator credits and 95.6 percent of lost opportunity cost credits. Since September 1, 2021, combined cycle units and combustion turbines have received 66.6 percent of dispatch differential lost opportunity credits.
- **Economic and Noneconomic Generation.** In 2021, 89.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 65.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2021, 0.2 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 50.6 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** In 2021, the top 10 units receiving energy uplift credits received 41.6 percent of all credits and the top 10 organizations received 87.3 percent of all credits. The HHI for day-ahead operating reserves was 7876, the HHI for balancing operating reserves was 2637 and the HHI for lost opportunity cost was 5728, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $11.0 million or 56.8 percent, in 2021 compared to 2020, from $19.3 million to $30.3 million.
- Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 96.7 percent of the $17.2 million. The day-ahead generation paid LOC credits for this reason decreased by 718.3 GWh or 55.7 percent during 2021, compared to 2020, from 1,288.7 GWh to 570.4 GWh.
- **Following Dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not

operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $14.8 million, of which PJM has resettled $1.5 million, or 9.9 percent.

- **Daily Uplift.** In 2021, balancing operating reserve charges would have been $27.0 million or 21.2 percent lower if they had been calculated on a daily basis rather than a segmented basis. In 2020, balancing operating reserve credits would have been $10.7 million or 18.5 percent lower if they had been calculated on a daily basis rather than a segmented basis. Uplift was designed to be charged on a daily basis and not on an intraday segmented basis.

Geography of Charges and Credits

- In 2021, 88.9 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 4.3 percent by transactions at hubs and aggregates, and 6.7 percent by transactions at interchange interfaces.
- In 2021, generators in the Eastern Region received 38.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2021, generators in the Western Region received 58.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2021, external generators received 3.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Section 4 Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the day-ahead energy market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Partially adopted, 2019.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead uplift, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported Q2, 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift for their startup cost when the

units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift (operating reserve) confidentiality rules in order to allow the disclosure of complete information about the level of uplift (operating reserve charges) by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[82])
- The MMU recommends that PJM eliminate the exemption for CTs and diesels from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

82 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

Section 4 Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus start up and no load costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its CT price setting logic. The same is true of fast start pricing. The same is true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing proposal (limited convex hull pricing). Fast start pricing was approved by FERC and implemented on September 1, 2021.[83] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[84]

83 See 173 FERC ¶ 61,244 (2020).
84 On March 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280 (2019).

However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability in the day-ahead market.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[85] The uplift payments for UTCs began on November 1, 2020.[86] This had been a longstanding recommendation of the MMU.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. they do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $14.8 million of incorrect uplift credits.

85 See 172 FERC ¶ 61,046 (2020).
86 On October 17, 2017, PJM filed a proposed tariff change at FERC to allocate uplift to UTC transactions in the same way uplift is allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. See 162 FERC ¶ 61,019 (2018).

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists and to stop creating incentives for inflexibility.

Overview: Section 5, Capacity Market

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[87]

Under RPM, capacity obligations are annual.[88] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[89] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[90] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade

87 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
88 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
89 See 126 FERC ¶ 61,275 at P 86 (2009).
90 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).

that was modeled in the BRA for the relevant delivery year.[91]

The 2021/2022 RPM Third Incremental Auction and the 2022/2023 RPM Base Residual Auction were conducted in 2021.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[92] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In 2021, RPM installed capacity increased 2,348.4 MW or 1.3 percent, from 184,245.0 MW on January 1, to 186,593.4 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** The sum of cleared MW that did not have a must offer requirement and the cleared MW of DR is 16,823.3 MW, or 100.7 percent of required reserves and 69.0 percent of total reserves. These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2021, 46.3 percent was gas; 26.0 percent was coal; 17.3 percent was nuclear; 4.7 percent was hydroelectric; 3.0 percent was oil; 1.4 percent was wind; 0.3 percent was solid waste; and 1.0 percent was solar.
- **Market Concentration.** In the 2021/2022 RPM Third Incremental Auction and the 2022/2023 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[93] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[94] [95] [96]
- **Imports and Exports.** Of the 1,558.0 MW of imports in the 2022/2023 RPM Base Residual Auction, 1,558.0 MW cleared. Of the cleared imports, 954.9 MW (61.3 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,115.9 MW for June 1, 2021, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2021/2022 Delivery Year (16,233.9 MW) less purchases of replacement capacity (4,118.0 MW).

Market Conduct

- **2021/2022 RPM Third Incremental Auction.** Of the 481 generation resources that submitted Capacity Performance offers, the MMU calculated unit

91 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.

92 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

93 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

94 See OATT Attachment DD § 6.5.

95 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

96 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

specific offer caps for zero generation resources (0.0 percent).

- **2022/2023 RPM Base Residual Auction.** Of the 1,083 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).

Market Performance

- The 2021/2022 RPM Third Incremental Auction and 2022/2023 RPM Base Residual Auction were conducted in 2021.[97] The weighted average capacity price for the 2020/2021 Delivery Year is $111.07 per MW-day, including all RPM auctions for the 2020/2021 Delivery Year. The weighted average capacity price for the 2021/2022 Delivery Year is $147.33 per MW-day, including all RPM auctions for the 2021/2022 Delivery Year.
- For the 2021/2022 Delivery Year, RPM annual charges to load are $9.4 billion.
- In the 2022/2023 RPM Base Residual Auction, the market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate. PJM has indicated to another plant that RMR service will be required in 2022.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in 2021 was 7.3 percent, an increase from 6.3 percent in 2020.[98]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2021 was 81.7 percent, a decrease from 84.7 percent in 2020.

Section 5 Recommendations[99]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[100] [101] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. EE should not be part of the capacity market. If EE is not included on the supply side, there is no reason to have an addback mechanism. If EE remains on the supply side, the MMU recommends that the implementation of the EE addback mechanism be modified to ensure that market clearing prices are not affected.[102] (Priority: Medium. First reported 2016. Status: Not adopted.)

97 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

98 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on January 24, 2022. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

99 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

100 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

101 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

102 Based on an Issue Charge introduced by the MMU, PJM has updated the EE addback rules effective with the 2023/2024 Delivery Year, to address this issue. "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 51 (Oct. 20, 2021).

- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and storage resources, including hydro. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding. (Priority: High. New recommendation. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[103] [104] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Adopted 2021.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA, at much lower prices, procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the

103 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
104 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

delivery year. (Priority: Medium. First reported Q3 2021. Status: Not adopted.)

- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. New recommendation. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[105] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[106] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal resources. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Adopted, 2021.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)

105 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

106 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that RMR service should be provided under the deactivation avoidable cost rate in Part V, and that the revenue cap under the avoidable cost rate option be eliminated. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets can and do have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2022/2023 BRA compared to a vertical demand curve was significant. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The small level of elasticity incorporated in the RPM demand curve is not adequate to modify this conclusion. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The level of cleared demand resources (8,710.3 MW) is greater than the entire level of excess capacity cleared in the auction (7,660.2 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called.

The market design for capacity leads to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes. The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[107] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were not implemented in the 2022/2023 BRA.[108] [109] The result was that capacity market prices were above the competitive level. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules. But the CP market seller offer cap was based on

107 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
108 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019s ("IMM MSOC Complaint").
109 176 FERC ¶ 61,137 (September 2nd Order).

strong assumptions that are not correct. The CP market seller offer cap was significantly overstated as a result. For units that could profitably provide energy under the Capacity Performance design even without a capacity payment because their expected CP bonus payments exceed their net ACR, based on expected unit specific performance, expected balancing ratio, expected performance assessment intervals (PAI) and expected penalty payments, the competitive, profit maximizing offer was defined to be Net CONE times B, where B is the expected average balancing ratio. This was the default offer cap for such units only under strong, defined assumptions.[110] Those assumptions included: there are expected PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses; the bonus payments equal the penalties; and capacity resources have the ability to costlessly switch between energy only status and capacity resource status.

But those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result. The Capacity Performance paradigm has not worked as anticipated in PJM and is not expected to work, in part because the assumptions are never likely to be correct. In addition, PAI is an endogenous variable. The expected number of PAI is a function of the level of capacity resources which is a function of offers and the resultant clearing prices. The correct definition of a competitive offer is net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties.

The MMU concludes that the results of the 2022/2023 RPM Base Residual Auction were not competitive as a result of economic withholding by resources that used offers that were consistent with the Net CONE times B offer cap but not consistent with competitive offers based on the correctly calculated offer cap. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. A competitive offer in the capacity market is equal to net ACR.[111] That is the way in which most market participants offered in this and prior capacity performance auctions. The ACR values used in this analysis were based on data provided by the participants and were consistent with competitive offers for the relevant capacity and were consistent with PJM's posted default ACR values for the referenced technology.

The MMU also concludes that market prices were significantly affected by other flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve, the overstatement of the capacity of intermittent resources, the treatment of DR, the MOPR rules, the inclusion of EE, and the EE addback rules.

The MMU also concludes that, although a much smaller issue in the 2022/2023 auction, the rules permitted the exercise of market power without mitigation for seasonal resources through uplift payments for noncompetitive offers, rather than through higher prices.[112] Although the impact was small in the 2022/2023 auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

The recent changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. The MMU had recommended that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes

110 For a detailed derivation, *see* Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).

111 See 174 FERC ¶ 61,212 at P 65 ("March 18th Order").

112 PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources, although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[113] [114] [115] [116] [117] [118] In 2020 and 2021, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 7,828.5 ICAP MW on June 1, 2021, and will have excess reserves of 8,065.8 ICAP MW on June 1, 2022, based on current positions.[119] A majority of capacity investments in PJM were financed by market sources.[120] Of the 42,969.5 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2021/2022 Delivery Years, 31,509.2 MW (73.3 percent) were based on market funding. Of the 6,587.3 MW of additional capacity that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years, 4,924.2 MW (74.8 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

113 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).
114 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
115 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).
116 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
117 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
118 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
119 The calculated reserve margin for June 1, 2022, does not account for cleared buy bids that have not been used in replacement capacity transactions.
120 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Overview: Section 6, Demand Response

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[121] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

  Total demand response revenue increased by $155.9 million, 43.4 percent, from $359.2 million in 2020 to $515.1 million in 2021. Emergency demand response revenue accounted for 97.9 percent of all demand response revenue, economic demand response for 0.1 percent, demand response in the synchronized reserve market for 1.5 percent and demand response in the regulation market for 0.4 percent.

  Total emergency demand response revenue increased by $149.4 million, 42.1 percent, from $355.1 million in 2020 to $504.4 million in 2021.[122]

  Economic demand response revenue increased by $0.4 million, 128.4 percent, from $0.3 million in 2020 to $0.8 million in 2021.[123] Demand response revenue in the synchronized reserve market increased by $5.2 million, 215.1 percent, from $2.4 million in 2020 to $7.6 million in2021. Demand response revenue in the regulation market increased by $1.0 million, 70.8 percent, from $1.4 million in 2020 to $2.3 million in 2021.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[124]

- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in 2020 and 2021. The HHI for economic resource reductions decreased by 539 points from 9065 for 2020 to 8526 in 2021. The ownership of emergency load response resources was highly concentrated in 2020. The HHI for emergency load response committed MW was 2523 for the 2020/2021 Delivery Year. In the 2020/2021 Delivery Year, the four largest CSPs owned 88.4 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2584 for the 2021/2022 Delivery Year. In the 2021/2022 Delivery Year, the four largest CSPs own 89.0 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. But PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Section 6 Recommendations

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately

121 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

122 The total credits and MWh numbers for demand resources were downloaded as of January 10, 2022 and may change as a result of continued PJM billing updates.

123 Economic credits are synonymous with revenue received for reductions under the economic load response program.

124 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 85 (Sep. 1, 2021).

incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)

- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[125] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[126] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the

125 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

126 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)

- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[127])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the synchronized reserve market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM Capacity Market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations. (Priority: Medium. New recommendation. Status: Not adopted.)

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to

127 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on how customers value the power and on the actual cost of that power.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. PJM automatically, and inappropriately, triggers a PAI when demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance resources.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called when economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

In order to be a substitute for generation, demand resources (DR) should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Interval (PAI) will be measured on a five-minute basis.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative to being a substitute for generation in the capacity and energy markets, demand response resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[128] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[129] [130] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance will be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[131] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE. But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side

128 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.

129 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed March 6, 2019).

130 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (Accessed March 6, 2019).

131 The PJM proposal from the SODRSTF weakened the proposal but was approved at the October 25, 2018 Members Committee meeting and PJM filed Tariff changes on December 7, 2018. See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market. That transition should be defined by the PRD rules, modified as proposed by the MMU.

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side.[132] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Overview: Section 7, Net Revenue

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and gas prices were significantly higher in 2021 than in 2020.
- In 2021, average energy market net revenues increased by 76 percent for a new combustion turbine (CT), 78 percent for a new combined cycle (CC), 642 percent for a new coal plant (CP), 86 percent for a new nuclear plant, 129 percent for a new diesel (DS), 67 percent for a new onshore wind installation, 83 percent for a new offshore wind installation and 77 percent for a new solar installation compared to 2020.
- The price of natural gas increased by significantly more than the price of coal in 2021. As a result, the marginal costs of a new CC and a new CT were greater than the marginal cost of a new CP in February 2021 and the marginal costs of a new CT were greater than the marginal cost of a new CP from July through November 2021 as a result of higher gas prices.
- Based on Western Hub prices, the spark spread in 2021 increased by 63 percent, the spark spread standard deviation increased by 104 percent, the dark spread increased by 208 percent, and the dark spread standard deviation increased by 112 percent.
- In 2021, capacity market revenue accounted for 52 percent of total net revenues for a new CT, 38 percent for a new CC, 83 percent for a new CP, 14 percent for a new nuclear plant, 85 percent for a new DS, 7 percent for a new onshore wind installation, 11 percent for a new offshore wind installation and 8 percent for a new solar installation.
- In 2021, a new CC would have received sufficient net revenue to cover levelized total costs in 14 zones. No new CT, CP, nuclear, or DS units would have received sufficient net revenue to cover levelized total costs in any zone.
- In 2021, a new entrant onshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. Net revenues would have covered between 45 and 51 percent of levelized total costs of a new entrant onshore wind installation in AEP, APS, COMED and PE. Renewable energy credits accounted for at least 28 percent of the total net revenue of an onshore wind installation.
- In 2021, a new entrant offshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the three zones analyzed. Net revenues would have covered between 28 and 32 percent of levelized total costs. Renewable energy credits accounted for 26 percent of the total net revenue of an offshore wind installation.
- In 2021, a new entrant solar installation would have covered more than 100 percent of levelized total costs in all five of the five zones analyzed. Renewable energy credits accounted for at least 59 percent of the total net revenue of a solar installation.
- In 2021, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2021, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units.

132 577 U.S. 260 (2016).

- All existing PJM nuclear plants more than covered their avoidable costs from energy and capacity market revenues in 2021 and are expected to more than cover their avoidable costs from energy and capacity market revenues in 2022.
- Using a forward analysis, a total of 2,230 MW of CT, diesel, and oil fired capacity are at risk of retirement, in addition to the units that are currently planning to retire or are expected to retire as a result of state and federal environmental regulations.

Section 7 Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 7 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[133] On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.[134] The list of coal steam units subject to MATS, however, remains in place.[135] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS. The EPA's May 22, 2020, finding is under review pursuant to Executive Order 13990.
- **Air Quality Standards (NO_x and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[136] On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[137]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[138] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.

133 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).

134 *See National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA–HQ–OAR–2018–0794, 85 Fed. Reg. 31286.

135 *Id.* at 31291.

136 CAA § 110(a)(2)(D)(i)(I).

137 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA–HQ–OAR–2020–0272; FRL–10013–42– OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).

138 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA–HQ–OAR–2018–0048; FRL–9997–95–OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[139] RICE do not have to meet the same emissions standards if they are emergency stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

  PJM does not prevent emergency stationary RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

- **Greenhouse Gas Emissions.** On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan (CPP), which ACE had replaced.[140] Neither the ACE nor CPP is currently effective.

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[141]

- **Waters of the United States.** On November 18, 2021, EPA and the Department the Army announced the signing of a proposed rule to revise the definition of "waters of the United States" to restore the pre 2015 definition of "waters of the United States." The proposed rule, if adopted, would make permanent the pre 2015 regulatory regime for interpreting WOTUS that is now effective.

- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. The EPA has recently been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result.

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[142] The EPA has adopted significant changes to the implementing regulations that will require closing non compliant impoundments, and, potentially, the host power plant. EPA is implementing a process for extensions to as late as October 17, 2028. EPA is reviewing applications received from PJM plant owners. So far, the EPA has proposed to reject applications for Gavin and Clifty Creek, and proposed to grant, with conditions, an application from Spurlock.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia that applies to power generation facilities. New Jersey rejoined on January 1, 2020.[143] Virginia joined RGGI on January 1, 2021, and Pennsylvania is preparing to join.[144] [145] The auction price in the December 1, 2021, auction was at the administrative price cap (Cost Containment Reserve (CCR) trigger price) of $13.00 per short ton, or $14.33 per metric tonne.

- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable

139 See 40 CFR § 63.6640(f).
140 American Lung Association et al. v. EPA, No. 19-1140.
141 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).
142 42 U.S.C. §§ 6901 *et seq.*
143 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.
144 "Statement on Virginia Greenhouse Gas Rule," RGGI, (July 8, 2020) <https://www.rggi.org/news-releases/rggi-releases>.
145 Executive Order–2019-07. Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis going forward. More than 10,000 MW of capacity are currently affected.

- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would increase by $24.52 per MWh or 65.0 percent for a new combustion turbine (CT) unit, $16.71 per MWh or 65.5 percent for a new combined cycle (CC) unit and $43.15 per MWh or 119.8 percent for a new coal plant (CP) for 2021.

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2021, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Virginia had a voluntary RPS in 2020, but a new mandatory RPS became effective on January 1, 2021. Indiana has voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $5.6 billion over the six year period from 2014 through 2019, an average annual RPS compliance cost of $936.7 million. The compliance cost for 2019, the most recent year with almost complete data, was $1.2 billion.[146]

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of December 31, 2021, 93.5 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.8 percent of coal steam MW had some type of particulate control, and 94.6 percent of fossil fuel fired capacity had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 4.2 percent of total generation in PJM in 2021. RPS Tier I generation was 5.7 percent of total generation in PJM and RPS Tier II generation was 2.2 percent of total generation in PJM in 2021. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)

146 The 2019 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets.

Environmental requirements and initiatives at both the federal and state levels, and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources and the retirement of emitting resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, including supporting some emitting resources, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

But in the absence of a PJM market carbon price, a single PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor.

RECs are an important mechanism used by PJM states to implement environmental policy. RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data.

Existing REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $11.33 per tonne in Washington, DC to $20.48 per tonne in Maryland. The price of carbon implied by SREC prices ranges from $69.30 per tonne in Pennsylvania to $867.85 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in December 2021 of $14.33 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[147] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.71 per MWh.[148] The impact of an $800 per tonne carbon price would be $267.30 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

If the states chose this policy option, PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. The results of the analysis would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state.

For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the six year period from 2014 through 2019 for the nine jurisdictions that had RPS was $936.7 million, or a total of $5.6 billion over six years. The RPS compliance cost for 2019, the most recent year for which there is almost

147 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

148 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.053070 tonne per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-7.

complete data, was $1.2 billion.[149] RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $3.7 billion per year if the carbon price were $13.00 per short ton and emissions levels were five percent below 2021 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $13.00 per short ton would be about $2.4 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2021, PJM was a monthly net exporter of energy in the real-time energy market in all months.[150] In 2021, the real-time net interchange was -37,766.5 GWh. The real-time net interchange in 2020 was -41,630.2 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2021, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In 2021, the total day-ahead net interchange was -25,538.8 GWh. The day-ahead net interchange in 2020 was -15,414.6 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2021, gross imports in the day-ahead energy market were 99.8 percent of gross imports in the real-time energy market (538.7 percent in 2020). In 2021, gross exports in the day-ahead energy market were 73.0 percent of the gross exports in the real-time energy market (104.4 percent in 2020).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2021, there were net scheduled exports at 14 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2021, there were net scheduled exports at six of PJM's nine interface pricing points eligible for real-time transactions in the real-time energy market.[151]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2021, there were net scheduled exports at 15 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2021, there were net scheduled exports at seven of PJM's nine interface pricing points eligible for day-ahead transactions in the day-ahead energy market.[152]
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2021, up to congestion transactions were net exports at three of PJM's nine interface pricing points eligible for day-ahead transactions in the day-ahead energy market.[153]
- **Inadvertent Interchange.** In 2021, net scheduled interchange was -37,767 GWh and net actual interchange was -37,813 GWh, a difference of 47 GWh. In 2020, the difference was 86 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2021, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -1,637 GWh of net scheduled interchange and -10,972 GWh of net actual interchange, a difference of 9,336 GWh. In 2021, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 1,769 GWh of net scheduled interchange and 10,298 GWh of net actual interchange, a difference of 8,529 GWh.

149 The 2019 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

150 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

151 On June 1, 2021, PJM consolidated the SouthIMP and SouthEXP interface pricing points to one new SOUTH interface pricing point. This reduces the number of real-time interface pricing points to eight.

152 On April 15, 2021, PJM retired the Southeast interface pricing point from the day-ahead market. The Southeast interface pricing point can still be assigned to transactions under the VACAR reserve sharing agreement in the Real-Time Market. On June 1, 2021, PJM consolidated the SouthIMP and SouthEXP interface pricing points to one new SOUTH interface pricing point. This reduces the number of day-ahead interface pricing points to seven.

153 Id.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2021, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 59.9 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 2021, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 56.6 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2021, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 74.8 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2021, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 76.8 percent of the hours.
- **Hudson DC Line.** In 2021, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 69.9 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in 2021, and two such TLRs in 2020.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market decreased by 46.6 percent, from 48,618 bids per day in 2020 to 25,965 bids per day in 2021. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 61.4 percent, from 438,170 MWh per day in 2020, to 169,201 MWh per day in 2021.

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the day-ahead and real-time energy markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SOUTH interface pricing point. (Priority: High. First reported 2013. Status: Partially adopted, Q2 2020.)[154]
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point.

154 The grandfathered agreements associated with the Southwest interface pricing point expired in 2012. The Southwest interface pricing point is no longer an eligible pricing point in the day-ahead or real-time energy markets. Effective June 1, 2020, PJM retired the NIPSCO interface pricing point.

(Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features of an energy market including locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features. Pricing in the market areas is transparent and pricing in the nonmarket areas is not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market across the interfaces.

It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. External entities wishing to receive the benefits of the PJM LMP market should join PJM.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. Following the termination of the Northwest pricing point on October 1, 2020, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The MMU continues to recommend the termination of the Southeast interface pricing point and the Ontario interface pricing point. The Southeast pricing point is inappropriately used to support a special agreement and the Ontario interface pricing point is noncontiguous to the PJM footprint that creates opportunities for market participants to engage in sham scheduling activities.

Overview: Section 10, Ancillary Services

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[155]

PJM determines the primary reserve requirement based on the most severe single contingency plus 190 MW in every approved RT SCED case. Every real-time market solution calculates the available tier 1 synchronized reserve. The required synchronized reserve and nonsynchronized reserve are calculated and dispatched in every real-time market solution, and there are associated clearing prices (SRMCP and NSRMCP) assigned every five minutes. Scheduled resources are credited based on a dispatched assignment and a five minute clearing price.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the most severe single contingency plus 190 MW. In 2021, the average primary reserve requirement was 2,449.6 MW in the RTO Zone and 2,436.4 in the MAD Subzone.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators and demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes in response to a PJM declared synchronized reserve event. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In 2021, there was an average hourly supply of 1,563.7 MW of tier 1 available in the RTO Zone and an average hourly supply of 788.2 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each real-time dispatch solution as the most severe single contingency plus 190 MW within both the RTO Zone and the MAD Subzone.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid for increasing its output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[156] This is the Synchronized Energy Premium Price.
- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from

155 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 40 (Dec. 15, 2021).

156 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 117 (Nov. 1, 2021).

the current economic dispatch point and the appropriate payment for responding to an event is the synchronized energy premium price of $50 per MWh. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rises above zero. This requirement is unnecessary and inconsistent with efficient markets. This rule has a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, $2,197,514 in 2017, $4,732,025 in 2018, $3,217,178 in 2019, $3,320,726 in 2020, and $7,354,224 in 2021. The nonsynchronized reserve market clearing price was above $0 in 2,015 intervals (1.9 percent of intervals) in 2020, none of which were during a spinning event. In 2021, the nonsynchronized reserve market clearing price was above $0 in 2.9 percent of all intervals resulting in a net payment of $7,364,936.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that may incur costs to be synchronized, and that have an obligation to respond to PJM declared synchronized reserve events. Tier 2 synchronized reserve is penalized for failure to respond to a PJM declared synchronized reserve event. In PJM the required amount of synchronized reserve is defined to be no less than the largest single contingency, and 10 minute primary reserve as no less than 150 percent of the largest single contingency, plus 190 MW. This is stricter than the NERC standard of the greater of 80 percent of the largest single contingency or 900 MW.[157]

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses the tier 2 synchronized reserve market to satisfy the balance of the requirement. The tier 2 synchronized reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In 2021, the supply of daily offered and eligible tier 2 synchronized reserve was 36,355.7 MW in the RTO Zone of which 4,606.9 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,697.1 MW in the RTO Reserve Zone and 1,696.5 in the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 274.1 MW in the MAD Subzone and 720.5 MW in the RTO.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in 2021.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 3460 which is classified as highly concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve, unless the unit type is exempt. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost which is calculated by PJM. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner. Demand resources offering into the tier 2 market are also subject to an offer cap of $7.50 plus costs. Cost may include shutdown costs for demand response.[158]

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the MAD subzone was $7.32 per MW in 2021. The weighted average price for tier 2 synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $8.87 per MW in 2021.

157 NERC (June 2, 2020) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

158 Ref. PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 117 (Nov. 1, 2021), para. 4.2.1, p. 92

Nonsynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. Generation owners do not submit supply offers for nonsynchronized reserve. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less (based on offer parameters), and on the resource opportunity costs calculated by PJM.

Market Structure

- **Supply.** In 2021, the average supply of eligible and available nonsynchronized reserve was 1,414.6 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[159]
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 99.96 percent of intervals where the price was above $0.01 in 2021.

Market Conduct

- **Offers.** Generation owners do not submit supply offers. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all intervals in the RTO Reserve Zone was $0.31 per MW in 2021.

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve in the day-ahead market as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but is not required to maintain this level of secondary reserve in real time.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The PJM Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[160] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

Market Structure

- **Supply.** The DASR market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all resources that can provide energy within 30 minutes of a request from PJM Dispatch.
- **Demand.** The DASR requirement is the sum of the PJM requirement and the Dominion requirement based on the VACAR reserve sharing agreement. It is calculated every year for the period November 1 through October 31. For November 1, 2020, through October 31, 2021, the DASR requirement was 4.75 percent of peak load forecast. For November 1, 2021, through October 31, 2022, the DASR requirement is 4.40 percent of peak load forecast. The average hourly DASR MW purchased in 2021 was 4,389.5 MW, a reduction from the 4,611.6 hourly MW in 2020.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal

159 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 117 (Nov. 1, 2021). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

160 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 117 (Nov. 1, 2021).

cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In 2021, 45.3 percent of daily unit offers were above $0.00 and 17.8 percent of daily unit offers were above $5.

- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in 2021.

Market Performance

- **Price.** In 2021, the MW weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.27. The MW weighted average for all hours including hours when the price was $0 was $0.24.

Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp rates. The RegD signal is designed for energy limited resources with fast ramp rates. In the regulation market RegD MW are converted to effective MW using a marginal rate of technical substitution (MRTS), called a marginal benefit factor (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the regulation market.

Market Structure

- **Supply.** In 2021, the average hourly offered supply of regulation for nonramp hours was 740.8 performance adjusted MW (744.9 effective MW). This was an increase of 19.9 performance adjusted MW (an increase of 23.7 effective MW) from 2020. In 2021, the average hourly offered supply of regulation for ramp hours was 1,066.4 performance adjusted MW (1,094.9 effective MW). This was an increase of 49.0 performance adjusted MW (an increase of 36.0 effective MW) from 2020, when the average hourly offered supply of regulation was 1,017.4 performance adjusted MW (1,058.9 effective MW).

- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.

- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 481.6 hourly average performance adjusted actual MW in 2021. This is an increase of 10.4 performance adjusted actual MW from 2020, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 492.0 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 707.3 hourly average performance adjusted actual MW in 2021. This is an increase of 4.9 performance adjusted actual MW from 2020, where the average hourly regulation cleared MW for ramp hours were 702.5 performance adjusted actual MW.

  The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.51 in 2021 (1.45 in 2020). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.54 in 2021 (1.47 in 2020).

- **Market Concentration.** In 2021, the three pivotal supplier test was failed in 85.9 percent of hours. In 2021, the actual MW weighted average HHI of RegA resources was 2215 which is highly concentrated and the weighted average HHI of RegD resources was 1585 which is moderately concentrated. The weighted average HHI of all resources was 1205, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[161] In 2021, there were 237 resources following the RegA signal and 53 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $26.00 per MW of regulation in 2021, an increase of $12.45 per MW, or 91.9 percent, from the weighted average clearing price of $13.55 per MW in 2020. The weighted average cost of regulation in 2021 was $31.49 per MW of regulation, an increase of 88.2 percent, from the weighted average cost of $16.73 per MW in 2020.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW.
- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[162]

In 2021, total black start charges were $68.0 million, including $67.6 million in revenue requirement charges and $0.3 million in uplift charges. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive payment. Black start uplift charges are paid to units scheduled in the day-ahead energy market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in 2021 ranged from $43,630 in the BGE Zone to $19,803,649 in the AEP Zone.

CRF values are a key determinant of total payments to black start units. The CRF values in PJM tariff tables should have been changed for both black start and the capacity market when the tax laws changed in December 2017. As a result, CRF values have overcompensated black start units since the changes to the tax code.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVAr and MW. The current rules permit double recovery of some fixed costs.

Reactive capability charges are based on FERC approved filings that permit recovery based on an outdated cost of service approach.[163] All capacity costs of generators should be incorporated in the capacity market. The nonmarket cost of service approach to reactive capability payments should be eliminated. Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Total reactive charges increased 6.19 percent from $346.4 million in 2020 to $367.8 million in 2021. Reactive capability charges increased 6.06 percent from $346.0 million in 2020 to $367.0 million in 2021. Total reactive service charges

161 See the *2019 State of the Market Report for PJM*, Vol. II, Appendix F "Ancillary Services Markets."

162 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.

163 OATT Schedule 2.

in 2021 ranged from $0 in the REC and OVEC Zones, to $49.2 million in the AEP Zone.

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[164] PJM filed revisions in compliance with Order No. 842 that incorporated the pro forma agreements into its market rules.[165]

The PJM Tariff requires that all new generator interconnection customers (Nuclear Regulatory Commission regulated facilities are exempt from this provision) have hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output in a direction to correct for frequency deviations. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 deadband.[166] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events remains under evaluation. A frequency event is declared when the frequency goes outside 60 Hz +/- 40 mHz for 60 continuous seconds. The NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to -259.3 MW/0.1 Hz and has selected twelve frequency events between December 1, 2020, and November 30, 2021, to evaluate.

As a balancing authority, PJM requires all generators to be capable of providing primary frequency response and to operate with primary frequency response controls enabled. PJM does monitor primary frequency response during NERC identified frequency events for all resources 50 MW or greater. Exclusions to PJM monitoring include nuclear plants, offline units, units with no available headroom, units assigned to regulation, and units with a current outage ticket in eDART.

Market Procurement of Real Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary reserves and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be weighed against the benefit the ancillary service provides. The degree to which PJM markets account for these interactions depends on the timing of the product clearing and software limitations and the accuracy of unit parameters and offers.

The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services. Resources categorized as flexible tier 2 reserve, those that can provide reserves by backing down according to their ramp rate, are jointly cleared along with energy in every real-time market solution. Given the joint clearing of energy and flexible tier 2, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible tier 2. PJM should never need to pay uplift to flexible tier 2. The uplift paid to flexible tier 2 results from issues with the dispatch and pricing software timing. Inflexible tier 2 reserves, provided by resources that require longer notice to take actions to prepare for reserve deployment, are not cleared along with energy in the real-time market solution. Inflexible tier 2 reserves are cleared hourly by the Ancillary Service Optimizer (ASO). The ASO uses forward looking information about the energy market, flexible tier 2, tier 1, and regulation to estimate the costs and benefits of using a resource for inflexible tier 2 synchronized reserves.

Nonsynchronized reserves are cleared with every real-time energy market solution, but their costs are not fully known by the real-time energy market software (RT SCED) because the resources are offline. PJM uses an estimate of the cost of using a resource for nonsynchronized

164 See 157 FERC ¶ 61,122 (2016).
165 See 164 FERC ¶ 61,224 (2018).
166 OATT Attachment O § 4.7.2 (Primary Frequency Response).

reserve instead of energy from a previously solved IT SCED solution. IT SCED runs every 15 minutes looking ahead at target dispatch times up to two hours in the future. The energy commitment decisions for the offline resources have already been made when the RT SCED clears the nonsynchronized reserve market. RT SCED compares the IT SCED estimated cost of nonsynchronized reserve clearing to the RT SCED determined cost of synchronized reserve clearing in satisfying the primary reserve requirement. Nonsynchronized reserve clearing indirectly interacts with energy clearing through both products' substitutability with synchronized reserves.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which is uses the RT SCED solution as an input. The RT SCED is partially, but not fully clearing the reserve market. The software determining the prices is not clearing the regulation market. With fast start pricing implementation on September 1, 2021, the pricing calculations in LPC are not the same prices that result from the market clearing in RT SCED.

Section 10 Recommendations

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.[167])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[168] FERC rejected.[169])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[170])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.[171])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[172])
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Not adopted.)

167 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
168 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
169 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
170 *Id.*
171 *Id.*
172 *Id.*

- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources be paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed because performance is only measured for events 10 minutes or longer. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that, in order to mitigate market power, offers in the DASR market be based on opportunity cost only. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The black start

units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported 2020. Status: Not adopted.)

- The MMU recommends for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Adopted 2021.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.[173] Status: Partially adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[174] (Priority: Medium. First reported 2020. Status: Not adopted.)

Section 10 Conclusion

The design of the PJM Regulation Market is significantly flawed.[175] The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017.[176] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[177] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[178]

The structure of the tier 2 synchronized reserve market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market clearing prices and with offers based on the marginal cost of producing the product plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, the $7.50 margin is not a cost. The margin is effectively a rule-based form of economic withholding and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. The

173 The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

174 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, <https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities>.

175 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

176 18 CFR § 385.211.

177 162 FERC ¶ 61,295 (2018).

178 170 FERC ¶ 61,259 (2020).

variable operating and maintenance component of the synchronized reserve offer should also be eliminated. All variable operating and maintenance costs are incurred to provide energy and to make units available to provide energy. There are no variable operating and maintenance costs associated with providing synchronized reserve. Reserve market design changes approved by FERC and scheduled for implementation in October 2022 will eliminate the $7.50 per MW margin and the variable operations and maintenance costs.[179]

Participant performance has not been adequate for tier 2 synchronized reserve. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. Actual participant performance means that the penalty structure is not an adequate incentive for performance. The October 2022 reserve market design changes do not respond to the MMU's recommendations to increase the penalties for nonperformance. All synchronized reserves should also have the same obligation to perform, but the proposed changes will mean that not all cleared reserves will be called on to perform during synchronized reserve events.[180]

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Tier 1 resources have no obligation to perform and pay no penalties if they do not perform, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are already paid for their response if they do respond to a synchronized reserve event. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule has added more than $100 million to the cost of primary reserve since 2014. The reserve market design changes approved by FERC and scheduled for implementation in 2022 will consolidate Tier 1 and Tier 2 reserves into a single synchronized reserve product, with a stronger must offer requirement and a single clearing price.[181] This will eliminate the payment of Tier 1 based on the nonzero nonsynchronized reserve price.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the regulation market results were not competitive, and the market design is significantly flawed. The MMU concludes that the synchronized reserve market results were competitive, although the $7.50 margin should be removed. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $466.6 million or 88.2 percent, from $528.7 million in 2020 to $995.3 million in 2021.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $563.7 million or 85.1 percent, from $662.5 million in 2020 to $1,226.2 million in 2021.
- **Balancing Congestion.** Negative balancing congestion costs increased by $97.1 million, from -$133.8 million in 2020 to -$230.9 million in 2021. Negative balancing explicit charges increased by $23.1 million, from -$77.6 million in 2020 to -$100.7 million in 2021.
- **Real-Time Congestion.** Real-time congestion costs increased by $706.7 million, from $749.3 million in 2020 to $1,456.0 million in 2021.

179 See FERC Docket No. EL19-58.

180 See PJM, "Intelligent Reserve Deployment – PJM Package (SRDTF)," Presentation to the Members Committee (January 26, 2022), <https://pjm.com/-/media/committees-groups/committees/mc/2022/20220126/20220126-cac-1-synchronous-reserve-deployment-presentation.ashx>.

181 See FERC Docket No. EL19-58.

- **Monthly Congestion.** Monthly total congestion costs in 2021 ranged from $29.1 million in January to $175.3 million in November.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern control zones in PJM were primarily a result of binding on the Three Mile Island Transformer, the Nottingham Series Reactor, the Cumberland - Juniata Line, the Conastone Transformer, and the Brighton Circuit Breaker.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in 2021. The number of congestion event hours in the day-ahead energy market was about twice the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency decreased by 27.9 percent from 78,239 congestion event hours in 2020 to 56,425 congestion event hours in 2021.

  Real-time congestion frequency increased by 4.9 percent from 21,984 congestion event hours in 2020 to 23,068 congestion event hours in 2021.
- **Congested Facilities.** The monthly average of daily day-ahead congestion event hours decreased in November 2020 as a result of decreased UTC activity due to a FERC order issued effective November 1, 2020, directing PJM to charge uplift to up to congestion transactions.[182] Day-ahead, congestion event hours decreased on all types of facilities except flowgates.

  The Three Mile Island Transformer was the largest contributor to congestion costs in 2021. With $88.2 million in total congestion costs, it accounted for 8.9 percent of the total PJM congestion costs in 2021.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. CT Price Setting Logic caused -$0.3 million of day-ahead congestion in 2021 and -$6.0 million of balancing congestion in 2021. While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals. None of the closed loop interfaces were binding in 2021 or 2020.
- **Zonal Congestion.** AEP had the highest zonal congestion costs among all control zones in 2021. AEP had $163.1 million in zonal congestion costs, comprised of $198.2 million in day-ahead congestion costs and -$35.1 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $476.3 million or 99.5 percent, from $478.5 million in 2020 to $954.8 million in 2021. The loss MWh in PJM increased by 953.8 GWh or 6.7 percent, from 14,317.2 GWh in 2020 to 15,271.0 GWh in 2021. The loss component of real-time LMP in 2021 was $0.02, compared to $0.01 in 2020.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $461.6 million or 87.7 percent, from $526.3 million in 2020 to $987.9 million in 2021.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $14.7 million or 30.7 percent, from -$47.7 million in 2020 to -$33.1 million in 2021.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $170.8 million or 107.1 percent, from $159.6 million in 2020, to $330.4 million in 2021.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2021 ranged from $42.5 million in April to $112.8 million in August.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $305.8 million or 96.4 percent, from -$317.4 million in 2020 to -$623.2 million in 2021.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $276.8 million or 68.9 percent, from -$401.4 million in 2020 to -$678.2 million in 2021.
- **Balancing System Energy Costs.** Balancing system energy costs decreased by $29.3 million or 35.9

182 172 FERC ¶ 61,046 (2020).

percent, from $81.6 million in 2020 to $52.3 million in 2021.

- **Monthly Total System Energy Costs.** Monthly total system energy costs in 2021 ranged from -$77.3 million in November to -$28.4 million in April.

Section 11 Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion costs increased by $466.6 million or 88.2 percent, from $528.7 million in 2020 to $995.3 million in 2021.

The monthly total congestion costs ranged from $29.1 million in January to $175.3 million in November in 2021.

The implementation of fast start pricing caused day-ahead congestion to increase by $1.3 million and caused negative balancing congestion to increase by $2.8 million over the September through December, 2021 period.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all congestion revenues. The congestion offset for the first seven months of the 2021/2022 planning period was 44.8 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first seven months of the 2021/2022 planning period, using the rules effective for each planning period, was 72.2 percent. Load has been underpaid by $2.7 billion from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2021, PJM had a total installed capacity of 199,195.3 MW, of which 49,074.4 MW (24.6 percent) are coal fired steam units, 52,094.7 MW (26.2 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 199,195.3 MW of installed capacity, 72,821.7 MW (36.6 percent) are from units older than 40 years, of which 37,643.4 MW (51.7 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 17,342.6 MW (23.8 percent) are nuclear units.

Generation Retirements[183]

- There are 48,406.2 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 37,420.2 MW (77.3 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost natural gas.
- In 2021, 1,307.8 MW of generation retired. The largest generators that retired in 2021 were the 667.0 MW Chalk Point Unit 1 and 2 coal fired steam units located in the PEPCO Zone. Of the 1,307.8 MW of generation that retired, 669.4 MW (51.2 percent) were located in the PEPCO Zone.
- As of December 31, 2021, there are 7,081.0 MW of generation that have requested retirement after December 31, 2021, of which 1,300.0 MW (18.4 percent) are located in the DUKE Zone. Of the generation requesting retirement in the DUKE Zone, all 1,300.0 MW (100.0 percent) are coal fired steam units.

183 See PJM. Planning. "Generator Deactivations," (Accessed on December 31, 2021) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

Generation Queue[184]

- There were 173,182.4 MW in generation queues, in the status of active, under construction or suspended, at the end of 2020. In 2021, the AG2 and AH1 queue windows closed, and the AH2 queue window opened. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On December 31, 2021, there were 254,914.6 MW in generation queues, in the status of active, under construction or suspended, an increase of 81,732.2 MW (47.2 percent) from the end of 2020.[185]
- As of December 31, 2021, 7,143 projects, representing 761,657.5 MW, have entered the queue process since its inception in 1998. Of those, 1,007 projects, representing 76,511.8 MW, went into service. Of the projects that entered the queue process, 3,269 projects, representing 430,231.1 MW (56.5 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- As of December 31, 2021, 254,914.6 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 41,074.4 MW (16.1 percent) of new generation in the queue are expected to go into service.
- The number of queue entries has increased during the past several years, primarily renewable projects. Of the 4,491 projects entered from January 2015 through December 2021, 3,344 projects (74.5 percent) were renewable. Of the 1,301 projects entered in 2021, 956 projects (73.5 percent) were renewable. Renewable projects make up 76.0 percent of all projects in the queue and those projects account for 75.1 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2021.

  But of the 191,352.4 MW of renewable projects in the queue, only 9,781.6 MW (5.1 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's cost/ benefit analysis that should be addressed prior to approval of additional projects. PJM's cost/benefit analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through December 31, 2021, PJM has completed four market efficiency cycles under Order No. 1000.[186]

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.

  But the use of an inaccurate cost/benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

184 See PJM. Planning. "New Services Queue," (Accessed on December 31, 2021) <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

185 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

186 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[187] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 770.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890[188]) to 174 for years 2008 through 2021 (post Order 890).

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project. Under the current approach, end of life projects are excluded from competition.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[189] In 2021, the PJM Board approved $1.11 billion in upgrades. As of December 31, 2021, the PJM Board has approved $38.9 billion in system enhancements since 1999.

187 See PJM. "Transmission Construction Status," (Accessed on December 31, 2021) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

188 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

189 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of December 31, 2021, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[190]
- There were 10,753 transmission outage requests submitted in the first seven months of the 2021/2022

190 See "PJM Manual 03: Transmission Operations," Rev. 60 (November 17, 2021).

planning period. Of the requested outages, 74.8 percent of the requested outages were planned for less than or equal to five days and 9.9 percent of requested outages were planned for greater than 30 days. Of the requested outages, 43.6 percent were late according to the rules in PJM's Manual 3.

Section 12 Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[191] (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing cost/benefit analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively

191 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[192]

- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[193]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[194] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, and apply the standard rules for late

192 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

193 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

194 See *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)

- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 12 Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require or even permit direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The MMU recognizes that the Commission has recently issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. PJM is in the process of developing and finalizing significant modifications to the queue process which are expected to be filed with FERC in 2022. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. But the behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The incentives for such behavior should also be addressed, including appropriate nonrefundable fees, appropriate credit requirements, appropriate limits on the use of the suspended option and appropriate milestone requirements.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current cost/benefit analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an inaccurate cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/ MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

If it is retained, there are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. The current cost/benefit analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The cost/benefit analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost benefit analysis.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the day-ahead energy market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules.

Overview: Section 13, FTRs and ARRs

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2021/2022 planning period ARRs were allocated to 1,459 individual participants, held by 131 parent companies. ARR ownership for the 2021/2022 planning period was unconcentrated with an HHI of 700.

Market Behavior

- **Self Scheduled FTRs.** For the 2021/2022 planning period, 26.1 percent of eligible ARRs were self scheduled as FTRs.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first seven months of the 2021/2022 planning period, ARRs offset only 44.8 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $2.7 billion from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period. The cumulative offset for that period was 72.2 percent of total congestion.
- **ARR Payments.** For the first seven months of the 2021/2022 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $626.8 million, while PJM collected $803.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2020/2021 planning period, the ARR target allocations were $517.1 million while PJM collected $691.2 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.
- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first seven months of the 2021/2022 planning period, PJM allocated a total of 18,624.9 MW of residual ARRs with a total target allocation of $11.4 million, up from 13,601.8 MW, with a total target allocation of $5.7 million, in the first seven months of the 2020/2021 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 29,776 MW of ARRs associated with $426,700 of revenue that were reassigned in the 2020/2021 planning period. There were 23,868 MW of ARRs associated with $434,400 of revenue that were reassigned for the first seven months of the 2021/2022 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions was changed effective with the 2020/2021 planning period. The new design includes auctions for each remaining month in the planning period. The prior design included auctions for the next three individual months plus remaining quarters.

Market Structure

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 83.2 percent of prevailing flow and 92.7

percent of counter flow FTRs for January through December, 2021. Financial entities owned 76.4 percent of all prevailing and counter flow FTRs, including 68.2 percent of all prevailing flow FTRs and 86.4 percent of all counter flow FTRs during the period from January through December 2021. Self scheduled FTRs account for 5.0 percent of all FTRs held.

- **Market Concentration.** For prevailing flow obligation FTRs in the Monthly Balance of Planning Period Auctions for the first seven months of the 2021/2022 planning period, ownership of cleared prevailing flow bids was unconcentrated in all of the periods. Ownership of cleared counter flow bids was unconcentrated in 74.6 percent of periods and moderately concentrated in 25.4 percent of periods, in the first seven months of the 2021/2022 planning period.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2021/2022 planning period, total participant FTR sell offers were 12,374,729 MW.
- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2021/2022 planning were 22,708,418 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $4.6 million for the 2020/2021 planning period. On May 20, 2021, FERC issued an order ruling the $0.01 definition of an increase in the value of an FTR unjust and unreasonable, but upheld the other parts of PJM's forfeiture rule, and required PJM to modify the rule. FERC did not rule on PJM's compliance filing. As a result, there was no FTR forfeiture rule in place from May 20, 2021 through the end of 2021.
- **Credit.** There were 10 collateral defaults in 2021. There were 10 payment defaults not involving GreenHat Energy, LLC for a total of $2.3 million. GreenHat Energy's default payments ended with the 2020/2021 planning period for a total of $179.5 million. Of the 20 defaults, 15 were promptly cured, and the remainder are awaiting resolution.

Market Performance

- **Quantity.** In the first seven months of the 2021/2022 planning period, Monthly Balance of Planning Period FTR Auctions cleared 4,324,179 (19.0 percent) of FTR buy bids and 2,463,546 MW (19.9 percent) of FTR sell offers. For the 2020/2021 planning period, Monthly Balance of Planning Period FTR Auctions cleared 2,720,662 (17.1 percent) of FTR buy bids and 2,770,301 MW (16.2 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods of the first seven months of the 2021/2022 planning period was $0.20 per MWh.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $41.6 million in the first seven months of the 2021/2022 planning period, up from $31.6 million for the same time period in the 2020/2021 planning period.
- **Revenue Adequacy.** The first seven months of the 2021/2022 planning period were revenue inadequate. FTRs were paid 91.1 percent of the target allocations for the first seven months of the 2021/2022 planning period, including distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. In the first seven months of the 2021/2022 planning period, physical entities received $118.6 million in profits on FTRs purchased directly (not self scheduled), up from $39.1 million profits in the same time period in the 2020/2021 planning period and financial entities received $252.6 million in profits, up from $141.3 million profits in the same time period in the 2020/2021 planning period.

Section 13 Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[195] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)

195 See "PJM Manual 6: Financial Transmission Rights," Rev. 27 (Aug. 25, 2021).

- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. New recommendation. Status: Not adopted.)

Section 13 Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by load of their congestion revenue rights.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives including so called revenue adequacy. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[196] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[197] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

A subsequent rule change was implemented that modified the allocation of surplus auction revenue to load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[198] ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. While this rule change increased the level of congestion revenues returned to load, the rules do not recognize ARR holders' rights to all congestion revenue. With this rule in effect for the first seven months of the 2021/2022 planning period, ARRs and FTRs offset 44.8 percent of total congestion. Load has been underpaid congestion revenues by $2.7 billion from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period. The cumulative offset for that period was 72.2 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs are entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

In response to a consultant's recommendations, PJM has proposed to increase Stage 1A ARR allocations to 60 percent of Network Service Peak Load (NSPL) ("Stage 1A Proposal").[199] [200] While PJM's proposal will increase Stage 1A rights, this will come at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's proposal will not improve the alignment of congestion property rights to load, but will exacerbate the current misalignment.

Under the current rules, Stage 1A allocations are limited to 50 percent of Network Service Base Load. In the 2021/2022 planning period there were infeasibilities on

196 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.

197 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

198 163 FERC ¶61,165 (2018).

199 *See* "Review of PJM's Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTRs)," London Economics, December 16, 202.

200 *See* "Auction Revenue Rights and Financial Transmission Rights Tariff and Operating Agreement Revisions," Docket No. ER22-000, January 10, 2022.

53 internal PJM constraints totaling 5,881 MW. These MW already result in revenue inadequacy because they are physically infeasible, but must be granted under the rules. In order to grant infeasible Stage 1A ARR allocations, PJM artificially increases the capacity of the constraint, which results in the over allocation issues of FTRs in the FTR auction. Increasing the amount of Stage 1 ARR allocations will exacerbate this issue and result in higher revenue inadequacy.

PJM's proposal is not internally consistent and does not follow its own logic. PJM's proposal does not extend the proposed changes beyond year one in the long term auction. The result is that buyers of long term FTRs can continue to purchase and hold capacity on the system before ARRs even have access to it. This increases over allocations and reduces load's access to ARRs.

PJM continues to fail to recognize the actual underlying issue. The only effective way to address the underlying issue identified by PJM's consultant, the fact that load does not actually get the rights to all congestion, is to modify the market design to assign congestion revenue rights to load.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the network congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy, and generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that will be credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with auction clearing price for the 50 percent of CRR that was sold to the third party. Depending on actual congestion, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM management, and the PJM Board; participates in PJM stakeholder meetings and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

The MMU is also tracking PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. Each recommendation includes a status. The status categories are:

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[6]

In this *2021 State of the Market Report for PJM*, the MMU includes 20 new recommendations made for 2021, 13 of which are new in this 2021 annual report.[7]

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.
6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
7 New recommendations include all MMU recommendations that were reported for the first time in the *2021 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2021.

New Recommendations from Section 3, Energy Market

- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends, if PJM implements extended downward sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on ten minute rather than 30 minute forecast error, and on forced outages in the ten minute rather than the 30 minute look ahead window to model the uncertainty in the inputs to RT SCED. (Priority: Medium. First reported Q2, 2021. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3, 2021. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 4, Energy Uplift

- The MMU recommends that units not be paid lost opportunity cost uplift when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported Q2, 2021. Status: Not adopted.)

New Recommendations from Section 5, Capacity Market

- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported Q3, 2021. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and storage resources, including hydro. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for

capacity be reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 6, Demand Response

- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 8, Environmental and Renewable Regulations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. Status: Not adopted.)[8]

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)

New Recommendation from Section 13, Financial Transmission Rights and Auction Revenue Rights

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. New recommendation. Status: Not adopted.)

History of MMU Recommendations

The MMU began making recommendations to PJM in the 1999 State of the Market Report. Since that time, the MMU has made 347 recommendations in the State of the Market Reports. In 2014, the MMU began including a priority and status with each recommendation. In this *2021 State of the Market Report for PJM*, the MMU has reviewed all past recommendations, assigned priority and determined their current status.

For the review of past recommendations, the MMU has refined the status assigned to each recommendation. The MMU uses additional definitions:

- **Partially Adopted (Continued Recommendation):** PJM has implemented part of the recommendation made by the MMU, and the MMU continues to recommend total adoption of the recommendation. These recommendations continue to be included in the main sections of this report;
- **Partially Adopted (Recommendation Closed):** PJM has implemented part of the recommendation made

8 This recommendation was first reported in 2010, but has been enhanced in the *2021 State of the Market Report for PJM.*

by the MMU, and the MMU has chosen to discontinue making the recommendation going forward. These recommendations are no longer included in the main sections of this report;

- **Not Adopted (Pending before FERC):** PJM has not yet implemented any part of the recommendation made by the MMU, but the subject of the recommendation is pending FERC action;
- **Not Adopted (Stakeholder Process):** PJM has not yet implemented any part of the recommendation made by the MMU, but the subject of the recommendation is pending stakeholder action;
- **Replaced by Newer Recommendation:** a recommendation that was discontinued when the MMU modified the recommendation;
- **Withdrawn (no longer relevant):** The MMU no longer makes the recommendation because it is no longer relevant; and
- **Withdrawn:** The MMU no longer makes the recommendation.

Table 2-1 shows the status of all recommendations reported by the MMU from 1999 through 2021. Over that time, 22 percent of all MMU recommendations have been adopted, 11 percent have been partially adopted, and 60 percent are not adopted. Of the 102 high priority recommendations, 30 (29 percent) have been adopted. Table 2-1 includes past recommendations that are no longer included in this report.

Table 2-1 Status of MMU reported recommendations: 1999 through 2021

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	30	22	25	77	22%
Partially Adopted - Stakeholder Process	0	0	0	0	0%
Partially Adopted - FERC	1	0	0	1	0%
Partially Adopted (Continued Recommendation)	10	12	6	28	8%
Partially Adopted (Recommendation Closed)	1	3	4	8	2%
Partially Adopted (Total)	12	15	10	37	11%
Not Adopted	53	102	43	198	57%
Not Adopted (Pending before FERC)	3	5	0	8	2%
Not Adopted (Stakeholder Process)	0	3	0	3	1%
Not Adopted (Total)	56	110	43	209	60%
Replaced by Newer Recommendation	2	8	3	13	4%
Withdrawn, No Longer Relevant	1	3	2	6	2%
Withdrawn	1	3	1	5	1%
Total	102	161	84	347	100%

Table 2-2 shows the number of recommendations associated with each of the sections in this report. The Energy Market, Capacity Market, and Ancillary Service Markets sections are the source of 52 percent of the recommendations.

Table 2-2 MMU reported recommendations by section and priority: 1999 through 2021

Current Section	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Section 1, Introduction (General Recommendations)	2	0	0	2	1%
Section 3, Energy Market	12	48	16	76	22%
Section 4, Energy Uplift	11	20	3	34	10%
Section 5, Capacity Market	24	28	10	62	18%
Section 6, Demand Response	13	13	9	35	10%
Section 7, Net Revenue	0	1	0	1	0%
Section 8, Environmental and Renewables	3	1	2	6	2%
Section 9, Interchange Transactions	6	11	12	29	8%
Section 10, Ancillary Service Markets	8	22	12	42	12%
Section 11, Congestion and Marginal Losses	0	1	1	2	1%
Section 12, Generation and Transmission Planning	1	14	12	27	8%
Section 13, Financial Transmission and Auction Revenue Rights	22	2	7	31	9%
Total	102	161	84	347	100%

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3 2021. Status: Not adopted.)
- The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)

- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. New recommendation. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Adopted 2021.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability

analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[9] [10] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends, if PJM implements extended downward sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on ten minute rather than 30 minute forecast error, and on forced outages in the ten minute rather than the 30 minute look ahead window to model the uncertainty in the inputs to RT SCED. (Priority: Medium. First reported Q2, 2021. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. New recommendation. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices, and all the constraints whose shadow

9 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

10 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

prices are included in reserve prices. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

Section 4, Energy Uplift

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the day-ahead energy market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Partially adopted, 2019.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead uplift, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported Q2, 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy

market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)

— The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)

— The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift (operating reserve) confidentiality rules in order to allow the disclosure of complete information about the level of uplift (operating reserve charges) by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[11])
- The MMU recommends that PJM eliminate the exemption for CTs and diesels from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Section 5, Capacity Market

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types,

11 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

including planned generation, demand resources and imports.[12 13] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. EE should not be part of the capacity market. If EE is not included on the supply side, there is no reason to have an addback mechanism. If EE remains on the supply side, the MMU recommends that the implementation of the EE addback mechanism be modified to ensure that market clearing prices are not affected.[14] (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and storage resources, including hydro. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding. (Priority: High. New recommendation. Status: Not adopted.)

12 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
13 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
14 Based on an Issue Charge introduced by the MMU, PJM has updated the EE addback rules effective with the 2023/2024 Delivery Year, to address this issue. "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 51 (Oct. 20, 2021).

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[15 16] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Adopted 2021.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of

15 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
16 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM not sell back any capacity in any IA, at much lower prices, procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported Q3 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. New recommendation. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[17] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[18] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal resources. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly

17 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

18 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

calculated. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Adopted, 2021.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a

return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)

- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that RMR service should be provided under the deactivation avoidable cost rate in Part V, and that the revenue cap under the avoidable cost rate option be eliminated. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 6, Demand Response

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[19] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to

19 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[20] (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[21])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the synchronized reserve market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM Capacity Market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in

20 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

21 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

addition to their EDC role. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations. (Priority: Medium. New recommendation. Status: Not adopted.)

Section 7, Net Revenue

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 8, Environmental and Renewables

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the day-ahead and real-time energy markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SOUTH interface

pricing point. (Priority: High. First reported 2013. Status: Partially adopted, Q2 2020.)[22]

- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 10, Ancillary Services

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the

22 The grandfathered agreements associated with the Southwest interface pricing point expired in 2012. The Southwest interface pricing point is no longer an eligible pricing point in the day-ahead or real-time energy markets. Effective June 1, 2020, PJM retired the NIPSCO interface pricing point.

optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.[23])

- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[24] FERC rejected.[25])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[26])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.[27])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[28])
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources be paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed because performance is only measured for events 10 minutes or longer. (Priority: Medium. First reported 2018. Status: Not adopted.)

23 162 FERC ¶ 61,295 (2018), reh'g denied, 170 FERC ¶ 61,259 (2020).
24 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
25 162 FERC ¶ 61,295 (2018), reh'g denied, 170 FERC ¶ 61,259 (2020).
26 *Id.*
27 *Id.*
28 *Id.*

- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that, in order to mitigate market power, offers in the DASR market be based on opportunity cost only. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The black start units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Adopted 2021.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.[29] Status: Partially adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[30] (Priority: Medium. First reported 2020. Status: Not adopted.)

29 The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

30 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, <https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities>.

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[31] (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing cost/benefit analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First

31 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

reported 2017. Status: Not adopted. Rejected by FERC.)[32]

- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[33]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[34] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, and apply the standard rules for late

32 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

33 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

34 See *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)

- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 13, FTRs and ARRs

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[35] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. New recommendation. Status: Not adopted.)

Adopted Recommendations

The following is the complete list of all MMU recommendations that have been adopted by PJM, including the priority, date of first report, date of last report, and the section in the State of the Market Report in which the recommendation was made.

Adopted 2021

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Last reported 2021. Section 3, Energy Market.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Last reported 2021. Section 5, Capacity Market.)
- The MMU recommends that PJM update the values in the CRF table in the tariff when the components change. (Priority: High. First reported 2020. Last reported 2021. Section 5, Capacity Market.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[36] [37] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Last reported 2021. Section 5, Capacity Market.)
- The MMU recommends for oil tanks shared with other resources that only a proportionate share of

35 See "PJM Manual 6: Financial Transmission Rights," Rev. 27 (Aug. 25, 2021).

36 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

37 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Last reported 2021. Section 10, Ancillary Services.)

- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. First reported Q3, 2020. Last reported 2021. Section 13, Financial Transmission and Auction Revenue Rights.)

Adopted 2020

- The MMU recommends incorporating startup and notification times as additional parameters subject to limits in order to ensure the reliability of the grid, as well as to deter market manipulation by offering artificially lengthy startup and notification time parameters to withhold generation from the market. (Priority: Medium. First reported 2010. Last reported 2010, Section 3, Energy Market.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Last reported 2018, Section 3, Energy Market.)
- The MMU recommends that the tariff be changed to allow units to have fuel cost policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for fuel cost policies but should not be required. (Priority: Low. First reported 2018. Last reported 2020, Section 3, Energy Market.)
- The MMU recommends that PJM change the fuel cost policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved fuel cost policy be set to zero. (Priority: Low. First reported 2018. Last reported 2020, Section 3, Energy Market.)
- The MMU recommends changing the assignment of the Saskatchewan Power Company and Manitoba Hydro balancing authorities from the Northwest interface pricing point to the MISO interface pricing point and eliminating the Northwest interface pricing point from the day-ahead and real-time energy markets. (Priority: High. First reported Q1, 2020. Last reported 2020, Section 9, Interchange Transactions.)
- The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. (Priority: High. First reported Q2, 2020. Last reported 2020, Section 9, Interchange Transactions.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Medium. First reported 2015. Last reported 2020, Section 12, Generation and Transmission Planning.)

Adopted 2019

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Last reported Q3, 2021, Section 3, Energy Market.)
- The MMU recommends that dispatchers classify the reasons for unit deselection and document all unit deselections. (Priority: Low. First reported 2009. Last reported 2009, Section 6, Ancillary Service Markets.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Last reported 2019, Section 9, Interchange Transactions.)
- The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must offer exception to permit the issue of CP status to be addressed. (Priority: Low. First reported 2018. Last reported

2020, Section 12, Generation and Transmission Planning.)

- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Last reported 2020, Section 13, FTRs and ARRs. Pending at FERC.)
- The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market. (Priority: High. First reported 2009. Last reported 2012, Section 3, Operating Reserve.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Last reported 2020, Section 10 Ancillary Service Markets.)

Adopted 2018

- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Last reported Q3, 2018, Section 4, Energy Uplift.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Last reported Q3, 2021, Section 4, Energy Uplift.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit uplift compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants must take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. Last reported 2018, Section 4, Energy Uplift.[38])

Adopted 2017

- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012. Last reported 2018 Q3, Section 9, Interchange Transactions.)
- The MMU recommends that PJM apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids. (Priority: High. First reported 2013. Last reported 2018 Q3, Section 13, Financial Transmission and Auction Revenue Rights.)

Adopted 2016

- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Last reported: 2018 Q3, Section 13, Financial Transmission and Auction Revenue Rights.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Last reported: 2018 Q3, Section 10, Ancillary Service Markets)

Adopted 2015

- The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2009. Last reported: 2018 Q3 Section 4, Energy Uplift.)
- The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid

38 Although this recommendation has not been adopted exactly as recommended by the MMU, the implementation of hourly offers by PJM has effectively adopted this recommendation.

to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 4, Energy Uplift.)

- The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 4, Energy Uplift.)
- The MMU recommends that all generation types face the same performance incentives. (Priority: High. First reported 2009. Last reported: 2012 Section 4, Capacity Market.)
- The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. (Priority: High. First reported 2009. Last reported: 2009 Section 5, Capacity Market.)
- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules. (Priority: High. First reported 2010. Last reported: 2011 Section 4, Capacity Market.)
- The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market. (Priority: Medium. First reported 2013. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends immediate elimination of lack of fuel as an acceptable basis for an OMC outage. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- PJM should scrutinize OMC outages for low Btu coal carefully. (Priority: Medium. First reported 2003. Last reported: 2009 Section 4, Capacity Market.)
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units. (Priority: Medium. First reported 2013. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2012. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period. (Priority: Low. First reported 2012. Last reported: 2012 Section 4 Capacity Market.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 5 Capacity Market.)
- The MMU recommends that the definition of demand side resources be modified to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2012. Last reported: 2018 Q3 Section 5 Capacity Market.)
- The MMU recommends that PJM increase the Capacity Resource Deficiency Charge, which is a penalty charge. (Priority: High. First reported 2013. Last reported: 2013 Section 5 Capacity Market.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border prior to offering in an RPM auction. (Priority: High. First reported 2014. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant Delivery Year in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. (Priority: High. First reported 2014. Last reported: 2017 Section 5, Capacity Market.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Last reported: 2018 Q3 Section 5, Capacity Market.)

- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Last reported: 2018 Q3 Section 6, Demand Response.)
- Continued development of appropriate credit protections for transactions in PJM markets that are consistent with those available to participants in bilateral transactions. (Priority: Low. First reported 2002. Last reported: 2002 Section: Recommendations.)

Adopted 2014

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Last reported: 2018 Q1 Section 3, Energy Market.)
- Pending elimination of these DR products, the MMU recommends that PJM procure the maximum amount of Annual and Extended Summer capacity resources available during an RPM auction, without impacting the clearing price. Currently, PJM procures a minimum level of Extended Summer and Annual Resources, but could procure additional MW of these superior products without a change in the clearing price. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (Priority: Low. First reported 2013. Last reported: 2018 Q3 Section 6, Demand Response.)
- The MMU recommends that the Enhanced energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced. (Priority: Low. First reported 2009. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that the rules for compliance with calls to respond to actual spinning events be reevaluated. (Priority: Low. First reported 2011. Last reported: 2012 Section 9, Ancillary Service Markets.)
- The MMU recommends that no payments be made to tier 1 synchronized reserve resources if they are deselected in the PJM market solution. The MMU also recommends that documentation of the tier 1 synchronized reserve deselection process be published. (Priority: High. First reported 2014. Status: Adopted, 2014. Last reported: 2018 Q3 Section 10, Ancillary Service Markets.)

Adopted 2013

- The PJM Tariff defines offer capped units as those units capped to maintain system reliability as a result of limits on transmission capability. Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules. (Priority: Low. First reported 2013. Last reported: 2014 Q1, Section 3, Energy Market.)
- The MMU recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction. (Priority: Low. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that not willing to pay congestion transactions are not permitted to flow in the presence of congestion. (Priority: Low. First reported 2009. Last reported: 2009 Section 4, Interchange Transactions.)
- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions). (Priority: Low. First reported 2010. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way

in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. PJM should have responsibility to prepare the black start restoration plan for the region, with Members playing an advisory role. PJM should have the responsibility to procure required black start service on a least cost basis through a transparent process. (Priority: Low. First reported 2009. Last reported: 2011 Section 9, Ancillary Service Markets.)

- The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market. (Priority: Low. First reported 2011. Last reported: 2011 Section 9, Ancillary Service Markets.)

Adopted 2012

- The MMU recommends that PJM should, on an expedited basis, request that the tariff be modified to permit allocation of day-ahead operating reserve charges consistent with the prior allocation of these charges in real time. This would be a short term solution to the issue created by shifting operating reserve charges to the Day-Ahead Energy Market and therefore changing the allocation of those charges. In addition, PJM should start a stakeholder process to consider the market design and cost allocation issues in detail and propose a permanent tariff change that results from the process. (Priority: High. First reported 2012. Last reported: 2012-Q3 Section 3, Operating Reserve.)
- The MMU recommends that PJM conduct a detailed review of the Day-Ahead Market software in order to address the issue of occasional anomalous loss factors and their effect on the day-ahead market results. (Priority: Low. First reported 2011. Last reported: 2011 Section 10, Congestion and Marginal Losses.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Last reported 2018 Q3, Section 3, Energy Market.)
- The MMU recommends the use of a single five minute clearing price based on actual five minute LMP and lost opportunity cost to improve the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Adopted in 2012. Last reported 2018 Q3, Section 10, Ancillary Service Markets.)

Adopted 2011

- The MMU recommends eliminating internal source and sink bus designations for external energy transactions in the Day-Ahead and Real-Time Energy Markets. (Priority: Low. First reported 2010. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members. (Priority: Low. First reported 2009. Last reported: 2010 Section 8, Financial Transmission and Auction Revenue Rights.)

Adopted 2010

- Implementation of rules governing the definition of final prices to ensure certainty for market participants. (Priority: High. First reported 2008. Last reported: 2009 Section 1, Introduction.)
- The MMU recommends the implementation of improved cost-based data submission to permit better monitoring and better analysis of markets. (Priority: Medium. First reported 2002. Last reported: 2009 Section 1, Introduction.)

Adopted 2009

- Retention and application of enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants that were implemented on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)
- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward

locational marginal value of capacity. (Priority: High. First reported 2006. Last reported: 2011 Section 4, Capacity.)

- Retention and application of the improved market power mitigation rules in the Regulation Market to prevent the exercise of market power in the Regulation Market while ensuring appropriate economic signals when investment is required and an efficient market mechanism. The PJM Regulation Market continues to be characterized by structural market power. PJM's application of targeted, flexible real-time, market power mitigation in the Regulation Market addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition. (Priority: High. First reported 2006. Last reported: 2009 Section 1, Introduction.)
- While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, LSE/EDCs should be able to initiate PJM settlement reviews. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- The MMU recommends ways to further improve the Economic program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation. This would include the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price and; required submission of detailed description of load reduction activities on specific days.
- The definition of CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions. When used to determine compliance in Load Management testing for GLD customers, the CBL calculation should include adjustments for ambient conditions.
- It is the MMU's recommendation that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should initiate a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.
- If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should initiate a CBL review and warrant further substantiation from the customer and CSP.
- Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen.

Adopted 2008

- Consistent application of local market power rules to all constraints. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)
- Retention and application of the improved local market power mitigation rules to prevent the exercise of local market power in the Energy Market while ensuring appropriate economic signals when investment is required. (Priority: Medium. First reported 2003. Last reported: 2009 Section 1, Introduction.)
- Consistent application of local market power rules to all units, including those currently exempt from offer capping. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)

Adopted 2006

- Modification of incentives in the capacity market to require all Load Serving Entities (LSEs) to meet their obligations to serve load on a longer-term basis and to require all capacity resources to be offered on a comparable longer term basis. (Priority: Medium. First reported 1999. Last reported: 2000 Section Summary.)

  Reevaluation of the criteria used to determine whether generating units qualify for capacity resource status. (Priority: Medium. First reported 1999. Last reported: 1999 Section Summary.)

Energy Market

The PJM energy market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in 2021.

Table 3-1 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in 2021 was, on average, unconcentrated by FERC HHI standards. Average HHI was 742 with a minimum of 532 and a maximum of 1115 in 2021. The intermediate segment was moderately concentrated. The peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to require competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for

competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market. PJM resolved the problems with real-time dispatch and pricing on November 1, 2021. The implementation of fast start pricing on September 1, 2021 undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.

- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.[1] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[2] In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. FERC recognized these issues in its June 17, 2021 order.[4] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

Overview

Supply and Demand

Market Structure

- **Supply.** In 2021, 3,990 MW of new resources were added in the energy market, and 1,308 MW of resources were retired.

  The real-time hourly on peak average offered supply was 139,027 MW in 2020, and 136,184 MW in 2021. The day-ahead hourly on peak average offered supply was 158,253 MW in 2020, and 155,811 MW in 2021.

1 OATT Attachment M (PJM Market Monitoring Plan).

2 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

4 175 FERC ¶ 61,231 (2021).

The real-time hourly average cleared generation in 2021 increased by 3.0 percent from 2020, from 90,938 MWh to 93,644 MWh.

The day-ahead hourly average supply in 2021, including INCs and UTCs, decreased by 8.1 percent from 2020, from 111,470 MWh to 102,431 MWh.

- **Demand.** The real-time hourly peak load plus exports in 2021 was 151,680 MWh (145,561 MWh of load plus 6,120 MWh of gross exports) in the HE 1800 on August 24, 2021, which was 1.8 percent, 2,684 MWh, higher than the PJM peak load plus exports in 2020, which was 148,996 MWh in the HE 1800 on July 20, 2020.

  The real-time hourly average load in 2021 increased by 3.6 percent from 2020, from 84,584 MWh to 87,606 MWh.

  The day-ahead hourly average demand in 2021, including DECs and UTCs, decreased by 8.2 percent from 2020, from 106,209 MWh to 97,537 MWh.

Market Behavior

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW decreased by 12.1 percent and cleared MW decreased by 4.5 percent in 2021 compared to 2020. The hourly average submitted decrement bid MW increased by 12.0 percent and cleared MW decreased by 2.4 percent in 2021 compared to 2020. The hourly average submitted up to congestion bid MW decreased by 58.2 percent and cleared MW decreased by 61.4 percent in 2021 compared to 2020.

Market Performance

- **Generation Fuel Mix.** In 2021, generation from coal units increased 17.8 percent, generation from natural gas units decreased 2.3 percent, and generation from oil increased 11.5 percent compared to 2020. Wind and solar output rose by 15.7 percent compared to 2020, supplying 4.2 percent of PJM energy in 2021.

- **Fuel Diversity.** The fuel diversity of energy generation in 2021, measured by the fuel diversity index for energy (FDI_e), increased 1.8 percent compared to 2020.

- **Marginal Resources.** In the PJM Real-Time Energy Market in 2021, coal units were 14.1 percent and natural gas units were 71.7 percent of marginal resources. In 2020, coal units were 17.5 percent and natural gas units were 72.6 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in 2021, UTCs were 35.2 percent, INCs were 17.9 percent, DECs were 27.1 percent, and generation resources were 19.5 percent of marginal resources. In 2020, UTCs were 51.4 percent, INCs were 13.2 percent, DECs were 18.8 percent, and generation resources were 16.5 percent of marginal resources.

- **Prices.** The real-time load-weighted average LMP in 2021 increased 82.8 percent from 2020, from $21.77 per MWh to $39.78 per MWh.

  The day-ahead load-weighted average LMP in 2021 increased 84.0 percent from 2020, from $21.40 per MWh to $39.37 per MWh.

- **Fast Start Pricing.** The real-time load-weighted average PLMP was $52.20 per MWh for September 1, 2021, through December 31, 2021, which is 5.5 percent, $2.73 per MWh, higher than the real-time load-weighted average DLMP of $49.47 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market in 2021, 10.2 percent of the load-weighted LMP was the result of coal costs, 53.9 percent was the result of gas costs and 3.2 percent was the result of the cost of emission allowances. In 2021, 8.3 percent of load-weighted LMP was the result of the transmission constraint violation penalty factor due to an increased frequency of transmission constraint violations, especially on the 500 kV system. PJM implemented Fast Start Pricing on September 1, 2021, which explicitly allowed commitment costs to affect LMPs. In the first four months of the fast start pricing in PJM, 3.4 percent of the real-time load-weighted average LMP was the result of commitment costs.

  In the PJM Day-Ahead Energy Market in 2021, 25.9 percent of the load-weighted LMP was the result of gas costs, 11.2 percent was the result of coal costs, 29.7 percent was the result of DEC bids, 17.2 percent was the result of INC offers, 5.7 percent was the result of positive markup, and 0.8 percent was the result of UTCs. In the first four months of fast start pricing in PJM, 0.4 percent of the day-ahead load-weighted average LMP was the result of commitment costs.

- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The difference between day-ahead and real-time average prices was $0.42 per MWh in 2021, and $0.33 per MWh in 2020. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were 28 intervals with five minute shortage pricing in 2021. There were no emergency actions that resulted in Performance Assessment Intervals in 2021.
- There were 5,590 five minute intervals, or 5.3 percent of all five minute intervals, in 2021 for which at least one RT SCED solution showed a shortage of reserves, and 1,572 five minute intervals, or 1.5 percent of all five minute intervals, in 2021 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for 28 five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Three suppliers were jointly pivotal in the day-ahead market on 301 days in 2020 and 286 days in 2021.
- **Local Market Power.** In 2021, 11 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. For three out of the top 10 congested facilities (by real-time binding hours) in 2021, the average number of suppliers providing constraint relief was three or less. There is a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure is not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 1.6 percent in 2020 and 2021. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.0 percent in 2020 to 1.5 percent in 2021. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

  The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in 2020 to 0.02 percent in 2021. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in 2020 to 0.03 percent in 2021. The low offer cap percentages do not mean that units manually committed for reliability reasons

do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment even if it has less flexible operating parameters.

- **Parameter Mitigation.** In 2021, 28.0 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. In 2021, on days when hot weather and cold weather alerts were declared, 32.6 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder, in January.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -0.01 in 2021, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in 2021 was more than $450 per MWh when using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was 0.07 in 2021, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in 2021 was more than $140 per MWh when using unadjusted cost-based offers.
- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Market Performance

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

  In the PJM Real-Time Energy Market in 2021, the unadjusted markup component of LMP was $1.69 per MWh or 4.2 percent of the PJM load-weighted average LMP. August had the highest unadjusted peak markup component, $6.68 per MWh, or 11.8 percent of the real-time peak hour load-weighted average LMP for August.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2021, the unadjusted markup component of LMP was $1.22 per MWh or 3.1 percent of the PJM day-ahead load-weighted average LMP. October had the highest unadjusted peak markup component, $8.06 per MWh, or 12.0 percent of the day-ahead peak hour load-weighted average LMP for October.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.
- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 4.7 percent of all real-time marginal unit intervals in 2021, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.
- **Markup and Aggregate Market Power.** In 2021, pivotal suppliers in the aggregate market set prices with high markups for some real-time market intervals.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)

- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3 2021. Status: Not adopted.)
- The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)

- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. New recommendation. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Adopted 2021.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub

definitions and a description of how hub definitions have changed.[5] [6] (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends, if PJM implements extended downward sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on ten minute rather than 30 minute forecast error, and on forced outages in the ten minute rather than the 30 minute look ahead window to model the uncertainty in the inputs to RT SCED. (Priority: Medium. First reported Q2, 2021. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. New recommendation. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send

5 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

6 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2021, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

PJM real-time hourly average load in 2021 increased by 3.6 percent from 2020, from 84,584 MWh to 87,606 MWh. The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[7] However, there are some issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021.[8] PJM continues to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[9] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021, and continues to recommend them.[10]

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs. This rule also had

7 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
8 See 175 FERC ¶ 61,231 (2021).
9 *See* PJM. "Answer of PJM Interconnection L.L.C.," Docket No. EL21-78 (September 15, 2021).
10 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).

unintended consequences for market seller offer caps in the capacity market. Maintenance costs includable in energy offers cannot be included in capacity market offer caps based on avoidable costs. As a result, capacity market offer caps based on net avoidable costs were lower than they would have been if maintenance costs had been correctly included in avoidable costs rather than incorrectly defined to be part of short marginal costs of producing energy and includable in energy offers.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market. In a competitive market, prices are directly related to the marginal cost to serve load at a given time. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2021 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel, staff their units, and operate rather than economically withhold or physically withhold.

Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices were a primary cause of low PJM energy market prices from 2017 to 2020. Higher natural gas prices are a primary cause of higher prices in 2021. There is no evidence to support significant changes to the calculation of LMP, such as fast start pricing or the extended ORDC. Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The extended ORDCs would have created shortage pricing when no reserve shortages exist and, in emergency situations, would have resulted in unjustifiable wealth transfers due to extreme high pricing with no demonstrable market benefit. These changes are unnecessary and distort, rather than improve, price formation. PJM appropriately and directly addressed price formation with the changes that went into effect on November 1, 2021, to resolve the timing mismatch between pricing (LPC) and dispatch instructions (RT SCED). Other potential areas for improvements in price formation include shortage pricing, operator actions and the design of reserve markets. FERC's December 22, 2021, order reversed its prior approval of PJM's proposed extended ORDCs, but accepted other changes to the reserve market design, including the consolidation of tier 1 and tier 2 synchronized reserves and the addition of a day-ahead reserve market. The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to addressed.[11] There are also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels (the current triggers are based on estimates that result from inaccurate generator modeling, and PJM's administrative overrides on eligibility of units to provide reserves) and the lack of adequate locational scarcity pricing options.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission line limit violations. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modified the values offered by generators and limits the MW available to the RT SCED through the first 10 months of 2021.[12] Rather than sending dispatch signals consistent with resource offers and holding resources accountable when they fail to follow them, DGP accommodated resources that did not follow dispatch. PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. PJM should evaluate its interventions in the market, consider

11 177 FERC ¶ 61,209 (2021).
12 DGP in the calculation of energy dispatch was removed as of November 1, 2021.

whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[13] The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders.

Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing. While the magnitude of the new payments was small in 2021, their effects on behavior are not clear yet.

PJM's arguments for changing energy market price formation asserted that fast start pricing and the extended ORDC would price flexibility in the market, but instead they will benefit inflexible units. The fast start pricing and extended ORDC solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units, for investment in increased flexibility of existing units, and for operating at the full extent of existing flexibility should be addressed directly.

13 See 173 FERC ¶ 61,244 (2020).

The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised and ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would have done, is not scarcity pricing but simply a revenue enhancement mechanism, which could have unintended consequences in an emergency, as was the case in ERCOT in February 2021. The Commission recognized that PJM's ORDC changes were not consistent with efficient market design and were just a revenue enhancement mechanism.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in 2021 or prior years. In 2021, marginal units were predominantly combined cycle gas generators. The frequency of combined cycle gas units as the marginal unit type has risen rapidly, from 31.2 percent in 2016 to 71.7 percent in 2021. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units have placed competitive pressure on less efficient generators, and the market has reliably served load with less congestion, less uplift, and less markup as a result. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in 2021.

Supply and Demand

Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In 2021, 3,990 MW of new resources were added in the energy market, and 1,308 MW of resources were retired. Figure 3-1 shows real-time and day-ahead hourly supply curves in 2020 and 2021.[14] [15] The real-time supply curve includes hourly on peak average offers. The real-time supply curve includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows all available hourly on peak average offers.

Figure 3-1 Real-time and day-ahead hourly supply curves: 2020 and 2021

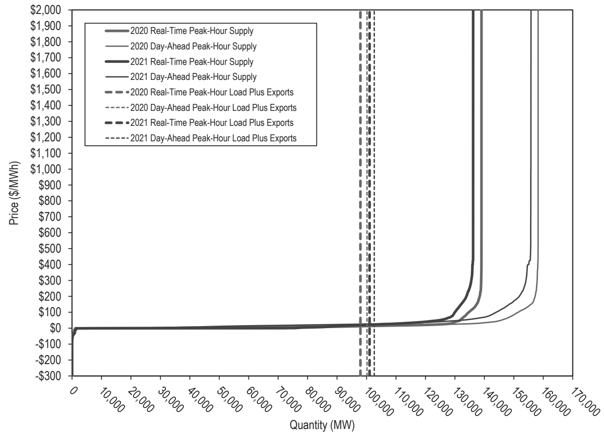


Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

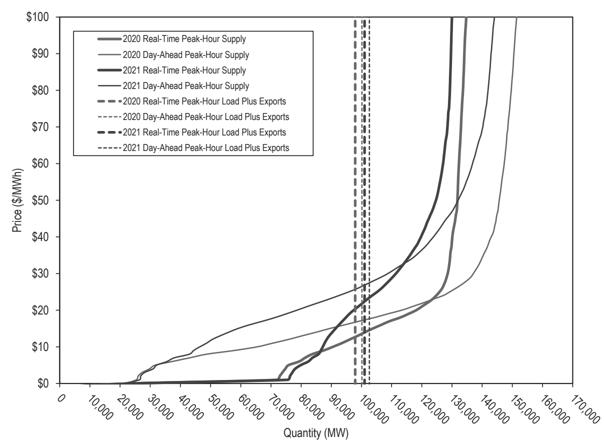


Table 3-2 shows the price elasticity of the real-time supply curve for the on peak hours in 2019 through 2021 by load level.

The price elasticity of the supply curve measures the responsiveness of the quantity supplied (GW) to a change in price:

$$\text{Elasticity of Supply} = \frac{\text{Percent change in quantity supplied}}{\text{Percent change in price}}$$

The supply curve is defined to be elastic when elasticity is greater than 1.0. The quantity supplied is more sensitive to changes in price the higher the elasticity. Although

14 Real-time supply includes real-time generation offers and import MWh.
15 The supply curve period is from January 1 to December 31.

the aggregate supply curve may appear flat as a result of the wide range in prices and quantities, the calculated elasticity is low throughout. The supply curve in 2021 was less elastic at all load levels compared to 2020.

Table 3-2 Price elasticity of the supply curve

	Elasticity of Supply Curve		
GW	2019	2020	2021
Min - 75	-	0.021	0.010
75 - 95	0.019	0.213	0.031
95 - 115	0.389	0.348	0.251
115 - 135	0.042	0.031	0.018
135 - Max	0.006	0.003	0.001

Real-Time Supply

The real-time hourly average cleared generation in 2021 increased by 3.0 percent from 2020, from 90,938 MWh to 93,644 MWh.[16]

The real-time hourly average cleared supply including imports in 2021 increased by 3.1 percent from 2020, from 91,674 MWh to 94,501 MWh.

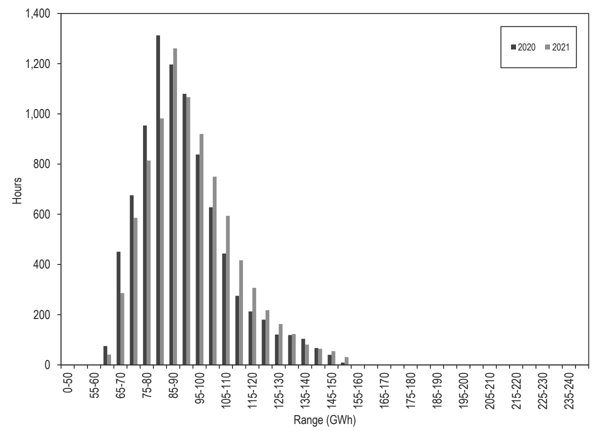
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the fixed MW.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Frequency

Figure 3-3 shows the hourly distribution of the real-time generation plus imports in 2020 and 2021.

Figure 3-3 Distribution of real-time generation plus imports: 2020 and 2021[17]



16 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

17 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time Average Supply

Table 3-3 shows the real-time hourly average supply and its standard deviation for 2001 through 2021.

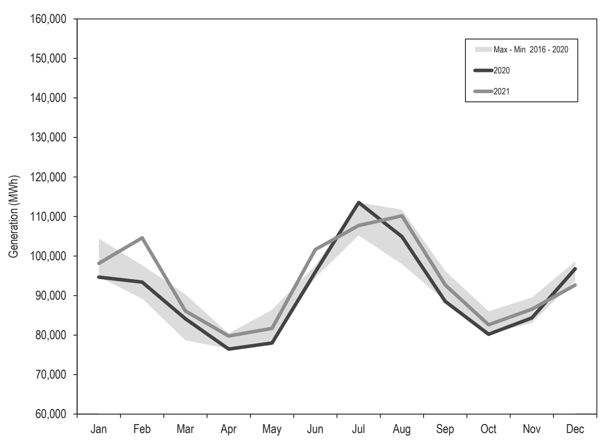
Table 3-3 Real-time hourly average generation and generation plus imports: 2001 through 2021

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,553	4,937	32,552	5,285	NA	NA	NA	NA
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	90,894	15,151	96,295	16,199	1.3%	0.9%	1.5%	2.0%
2015	88,628	16,118	94,330	17,313	(2.5%)	6.4%	(2.0%)	6.9%
2016	91,304	17,731	95,054	17,980	3.0%	10.0%	0.8%	3.9%
2017	90,945	15,194	92,721	15,493	(0.4%)	(14.3%)	(2.5%)	(13.8%)
2018	94,236	16,326	96,109	16,595	3.6%	7.5%	3.7%	7.1%
2019	93,434	16,357	94,618	16,515	(0.9%)	0.2%	(1.6%)	(0.5%)
2020	90,938	16,527	91,674	16,627	(2.7%)	1.0%	(3.1%)	0.7%
2021	93,644	16,786	94,501	16,884	3.0%	1.6%	3.1%	1.5%

PJM Real-Time Monthly Average Generation

Figure 3-4 compares the real-time monthly average generation in 2020 and 2021 with the historic five year range. In February and June 2021, the monthly average generation was higher than the maximum of the past five years, primarily as a result of weather related demand.

Figure 3-4 Real-time monthly average generation: 2020 through 2021



Day-Ahead Supply

The day-ahead hourly average supply in 2021, including INCs and UTCs, decreased by 8.1 percent from 2020, from 111,470 MWh to 102,431 MWh.

The day-ahead hourly average supply in 2021, including INCs, UTCs and exports, decreased by 8.1 percent from 2020, from 111,636 MWh to 102,599 MWh. The decrease in day-ahead supply was a result of a decrease in UTCs.

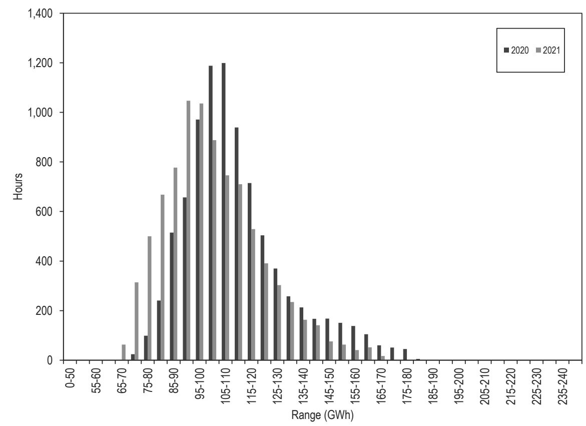
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the day-ahead energy market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the day-ahead energy market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-5 shows the distribution of the day-ahead hourly cleared supply, including increment offers, up to congestion transactions, and imports in 2020 and 2021.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: 2020 and 2021[18]



18 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead Average Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics from 2001 through 2021. The day-ahead hourly cleared supply in 2021 was the lowest since 2009.

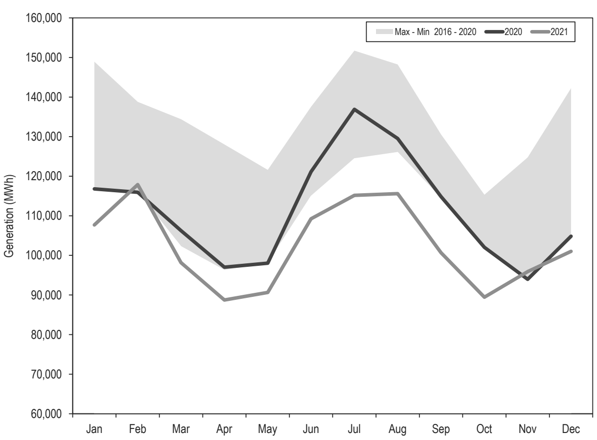
Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: 2001 through 2021

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,762	4,595	27,497	4,664	NA	NA	NA	NA
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	146,672	33,145	148,906	33,346	(1.1%)	76.5%	(1.1%)	75.7%
2015	114,890	19,165	117,147	19,406	(21.7%)	(42.2%)	(21.3%)	(41.8%)
2016	131,618	22,329	133,246	22,368	14.6%	16.5%	13.7%	15.3%
2017	130,603	20,035	131,142	20,153	(0.8%)	(10.3%)	(1.6%)	(9.9%)
2018	114,556	20,239	114,967	20,224	(12.3%)	1.0%	(12.3%)	0.4%
2019	117,250	18,909	117,622	18,881	2.4%	(6.6%)	2.3%	(6.6%)
2020	111,470	19,749	111,636	19,729	(4.9%)	4.4%	(5.1%)	4.5%
2021	102,431	18,823	102,599	18,850	(8.1%)	(4.7%)	(8.1%)	(4.5%)

PJM Day-Ahead Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead monthly average supply including increment offers and up to congestion transactions in 2020 and 2021 with the historic five year range. The average supply was lower than the minimum of the previous five years in most months as a result of the decrease in UTCs.

Figure 3-6 Day-ahead monthly average cleared supply: 2020 through 2021



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply in 2020 and 2021. The last two columns of Table 3-5 are the day-ahead supply minus the real-time supply. The first column is the total physical day-ahead generation less the total physical real-time generation and the second column is the total day-ahead supply less the total real-time supply.

Table 3-5 Day-ahead and real-time hourly supply (MWh): 2020 and 2021

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
		Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2020	90,786	2,427	18,257	166	111,636	90,938	91,674	(152)	19,962
	2021	93,069	2,312	7,050	168	102,599	93,644	94,501	(575)	8,098
Median	2020	87,852	2,364	19,196	125	107,798	88,101	88,828	(249)	18,970
	2021	90,444	2,222	6,833	106	99,893	90,902	91,800	(458)	8,093
Standard Deviation	2020	17,343	852	5,908	166	19,729	16,527	16,627	816	3,101
	2021	17,091	994	2,787	211	18,850	16,786	16,884	305	1,966
Peak Average	2020	99,578	2,758	18,960	152	121,448	98,939	99,714	639	21,734
	2021	101,851	2,794	8,072	164	112,880	101,997	102,919	(146)	9,961
Peak Median	2020	96,111	2,713	19,883	100	116,084	95,559	96,419	551	19,664
	2021	99,018	2,741	7,870	102	109,673	98,748	99,821	270	9,852
Peak Standard Deviation	2020	16,544	868	5,866	155	19,322	16,027	16,151	517	3,172
	2021	16,018	975	2,664	191	17,137	16,115	16,173	(97)	964
Off-Peak Average	2020	83,048	2,135	17,639	179	103,000	83,897	84,597	(848)	18,403
	2021	85,357	1,888	6,153	172	93,571	86,309	87,109	(952)	6,462
Off-Peak Median	2020	80,536	2,076	18,490	145	100,743	81,646	82,358	(1,110)	18,385
	2021	83,037	1,827	5,806	108	90,787	84,117	85,080	(1,080)	5,707
Off-Peak Standard Deviation	2020	14,025	721	5,877	174	15,618	13,475	13,538	550	2,080
	2021	14,005	797	2,576	227	15,334	13,643	13,742	363	1,592

Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day in 2021. The day-ahead supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time supply (Average volumes by hour of the day): 2021

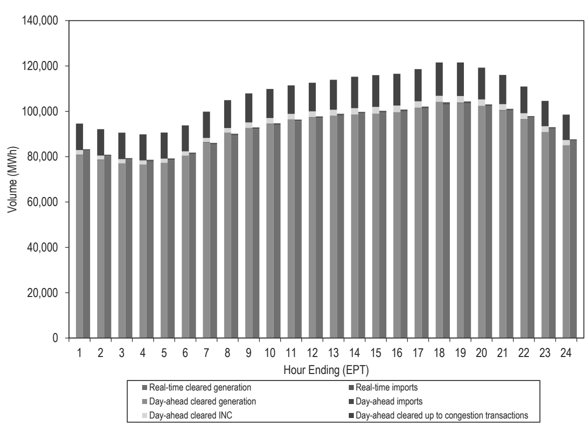
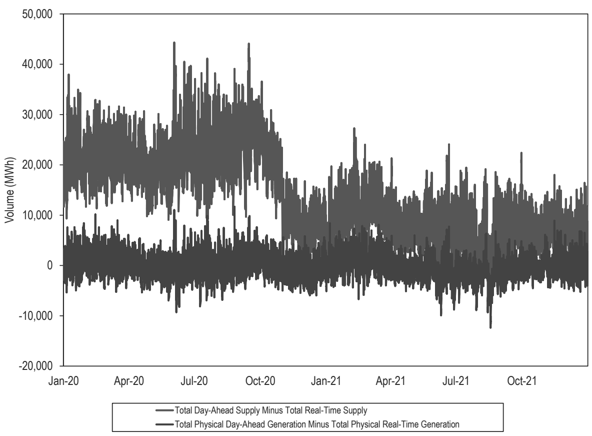


Figure 3-8 shows the difference between day-ahead and real-time daily average supply in 2020 and 2021.

Figure 3-8 Difference between day-ahead and real-time daily average supply: 2020 through 2021



Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports, and in the day-ahead energy market, includes virtual transactions.[19]

The real-time hourly peak load plus exports in 2021 was 151,680 MWh (145,561 MWh of load plus 6,120 MWh of gross exports) in the HE 1800 on August 24, 2021, which was 1.8 percent, 2,684 MWh, higher than the PJM peak load plus exports in 2020, which was 148,996 MWh in the HE 1800 on July 20, 2020.

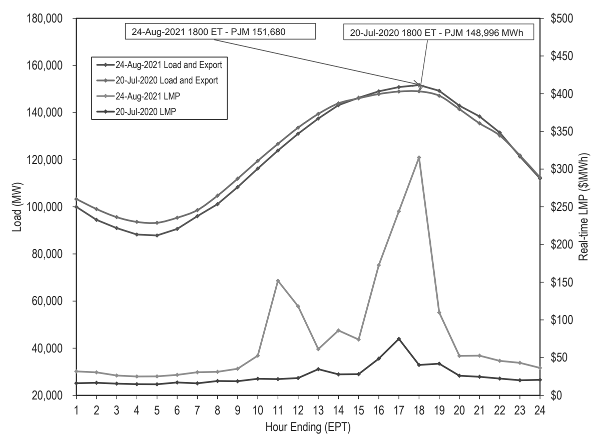
Table 3-6 shows the peak load plus export for 2009 through 2021.

Table 3-6 Actual footprint peak load plus export: 2009 through 2021[20 21]

	Date	Hour Ending (EPT)	PJM Load Plus Export (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Mon, August 10	16	135,923	NA	NA
2010	Wed, July 07	17	149,376	13,453	9.9%
2011	Thu, July 21	17	169,290	19,915	13.3%
2012	Tue, July 17	18	166,081	(3,210)	(1.9%)
2013	Thu, July 18	17	157,277	(8,804)	(5.3%)
2014	Tue, June 17	18	142,428	(14,850)	(9.4%)
2015	Fri, February 20	8	144,850	2,422	1.7%
2016	Thu, August 11	17	154,743	9,893	6.8%
2017	Thu, July 20	16	148,343	(6,400)	(4.1%)
2018	Tue, August 28	17	152,509	4,166	2.8%
2019	Fri, July 19	18	153,589	1,080	0.7%
2020	Mon, July 20	18	148,996	(4,593)	(3.0%)
2021	Tue, August 24	18	151,680	2,684	1.8%

Figure 3-9 compares prices and demand on the peak load days in 2020 and 2021. The real-time average LMP for July 20, 2020, peak load hour was $40.27 and for August 24, 2021, peak load hour it was $315.42.

Figure 3-9 Peak load and export day comparison: Monday, July 20, 2020 and Tuesday, August 24, 2021



Real-Time Demand

The real-time hourly average load in 2021 increased by 3.6 percent from 2020, from 84,584 MWh to 87,606 MWh.[22]

The real-time hourly average demand including exports in 2021 increased by 3.0 percent from 2020, from 90,059 MWh to 92,774 MWh.

19 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

20 Peak loads shown are Power accounting load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions," for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

21 Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017.

22 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

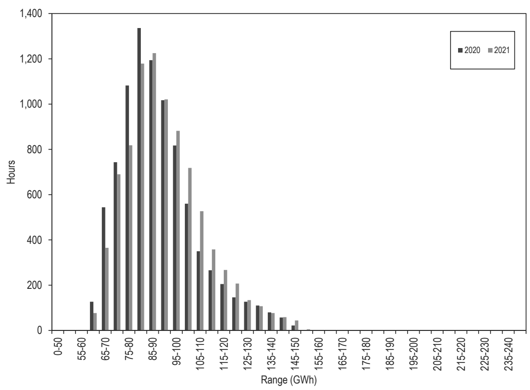
In the PJM Real-Time Energy Market, there are two types of demand:

- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority's checkout process.

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of the real-time hourly load plus exports in 2020 and 2021.[23]

Figure 3-10 Distribution of real-time load plus exports: 2020 and 2021[24]



PJM Real-Time Average Load

Table 3-7 presents real-time hourly demand summary statistics from 2001 through 2021.[25]

Table 3-7 Real-time hourly average load and load plus exports: 2001 through 2021

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,297	5,873	32,165	5,564	NA	NA	NA	NA
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%
2016	88,601	17,229	93,551	17,498	0.0%	3.4%	1.0%	4.3%
2017	86,618	15,170	91,015	15,083	(2.2%)	(11.9%)	(2.7%)	(13.8%)
2018	90,308	15,982	94,351	16,142	4.3%	5.4%	3.7%	7.0%
2019	88,120	15,867	92,920	16,085	(2.4%)	(0.7%)	(1.5%)	(0.4%)
2020	84,584	16,016	90,059	16,233	(4.0%)	0.9%	(3.1%)	0.9%
2021	87,606	15,725	92,774	16,485	3.6%	(1.8%)	3.0%	1.6%

23 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

24 Each range on the horizontal axis excludes the start value and includes the end value.

25 Accounting load is used because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the incorporation of marginal loss pricing in LMP.

PJM Real-Time Monthly Average Load

Figure 3-11 compares the real-time monthly average load plus exports in 2020 and 2021, with the historic five year range. The monthly average load plus exports in February and June in 2021 was higher than the maximum of the past five years, and in December was lower than the minimum of the past five years.

Figure 3-11 Real-time monthly average hourly load plus exports: 2020 through 2021

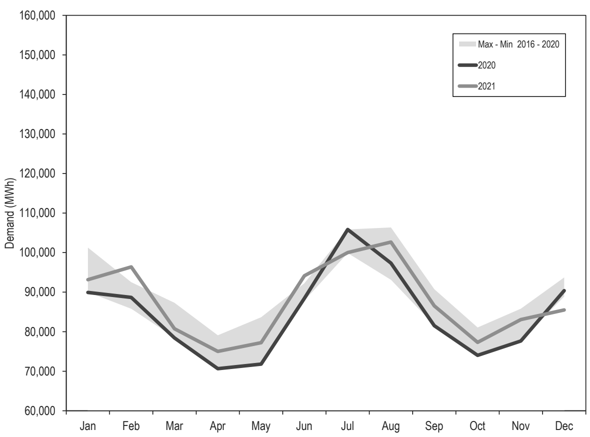
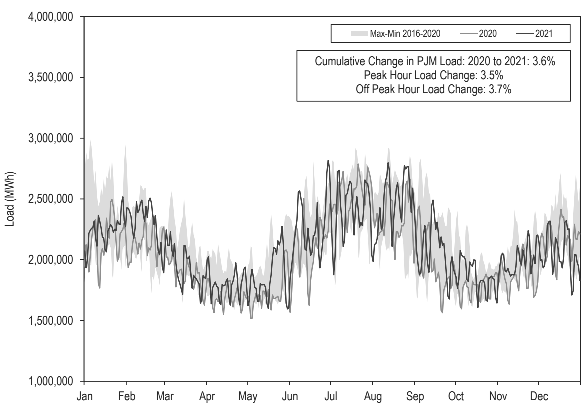


Figure 3-12 compares the real-time daily average load in 2020 and 2021, with the historic five year range.

Figure 3-12 Real-time daily load: 2020 through 2021



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and cooling degree days in 2020 and 2021.[26] Heating degree days increased 2.8 percent, and cooling degree days increased 4.8 percent compared to 2020.

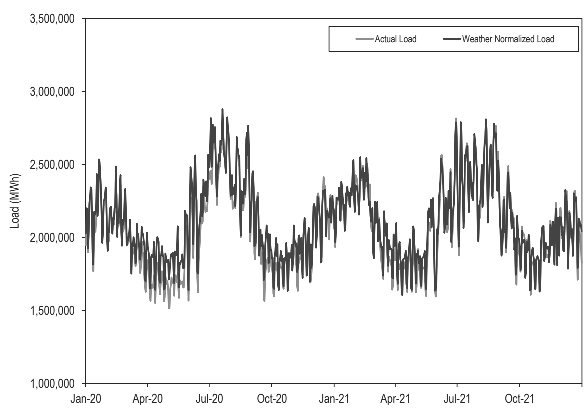
Table 3-8 Heating and cooling degree days: 2020 through 2021

	2020		2021		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	697.8	0.0	815.9	0.0	16.9%	0.0%
Feb	652.0	0.0	822.1	0.0	26.1%	0.0%
Mar	384.5	0.0	404.9	0.0	5.3%	0.0%
Apr	278.9	0.0	203.1	8.1	(27.2%)	0.0%
May	105.1	59.2	77.1	81.6	(26.7%)	37.8%
Jun	0.0	261.9	0.0	283.1	0.0%	8.1%
Jul	0.0	463.9	0.0	360.1	0.0%	(22.4%)
Aug	0.0	342.1	0.0	373.8	0.0%	9.3%
Sep	12.6	119.9	0.0	157.7	(100.0%)	31.6%
Oct	138.9	1.4	56.7	44.0	(59.2%)	2,932.8%
Nov	313.1	0.1	490.7	0.0	56.7%	0.0%
Dec	719.4	0.0	524.0	0.0	(27.2%)	0.0%
Total	3,302.3	1,248.6	3,394.5	1,308.4	2.8%	4.8%

Figure 3-13 shows the real-time daily load and the weather normalized load in 2020 and 2021.

Weather normalized load is calculated using the historic relationship between the daily load and HDD, CDD, and time of year for 2015 through 2018. Figure 3-13 shows that the actual load was significantly less than the weather normalized load from March through May 2020.

Figure 3-13 Real-time daily load and weather normalized load: 2020 and 2021



26 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Table 3-9 compares the monthly actual load and the weather normalized load. Actual load was 0.7 percent lower than weather normalized load in 2021, while actual load was 3.4 percent lower than weather normalized load in 2020.

Table 3-9 Actual load and weather normalized load: 2020 and 2021

	2020			2021		
	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference
Jan	66,905,774	68,256,113	(2.0%)	69,303,496	69,689,108	(0.6%)
Feb	61,717,353	62,471,212	(1.2%)	64,761,103	64,275,946	0.8%
Mar	58,258,178	60,459,812	(3.6%)	60,002,018	61,459,726	(2.4%)
Apr	50,864,950	55,116,626	(7.7%)	54,010,529	55,580,210	(2.8%)
May	53,430,088	57,904,128	(7.7%)	57,460,157	59,183,412	(2.9%)
Jun	63,666,037	67,406,845	(5.5%)	67,779,457	68,488,450	(1.0%)
Jul	78,749,183	80,856,404	(2.6%)	74,409,489	74,488,509	(0.1%)
Aug	72,425,029	74,173,773	(2.4%)	76,383,295	76,161,192	0.3%
Sep	58,683,018	60,988,913	(3.8%)	62,305,584	62,675,810	(0.6%)
Oct	55,061,813	56,572,150	(2.7%)	57,511,887	57,304,504	0.4%
Nov	55,993,432	57,678,640	(2.9%)	59,887,527	59,557,389	0.6%
Dec	67,232,280	67,074,317	0.2%	63,610,554	64,276,557	(1.0%)
Annual	742,987,135	768,958,933	(3.4%)	767,425,096	773,140,813	(0.7%)

Day-Ahead Demand

The day-ahead hourly average demand in 2021, including DECs and UTCs, decreased by 8.2 percent from 2020, from 106,209 MWh to 97,537 MWh.

The day-ahead hourly average demand in 2021, including DECs, UTCs and exports, decreased by 8.1 percent from 2020, from 109,506 MWh to 100,642 MWh.

In the PJM Day-Ahead Energy Market, there are five types of financially binding demand bids:

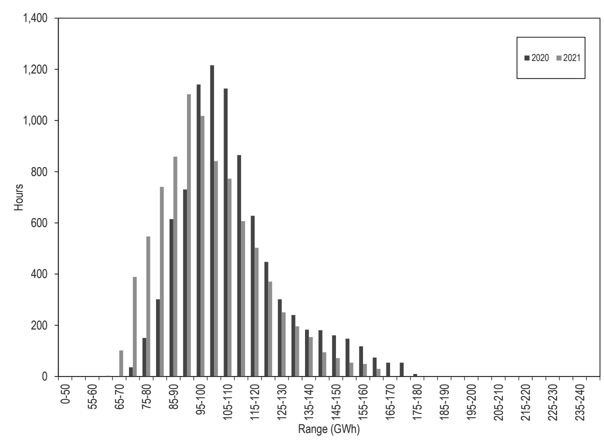
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the day-ahead energy market will not physically flow in real-time unless it is also submitted through the real-time energy market scheduling process.

PJM day-ahead demand is the total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-14 shows the hourly distribution of the day-ahead demand in 2020 and 2021.

Figure 3-14 Distribution of day-ahead demand plus exports: 2020 and 2021[27]



PJM Day-Ahead Average Demand

Table 3-10 shows day-ahead hourly average demand for 2001 through 2021. The hourly average demand in 2021, with and without exports, was lower than any year since 2009, as a result of the reduction in UTC transaction volumes.

27 Each range on the horizontal axis excludes the start value and includes the end value.

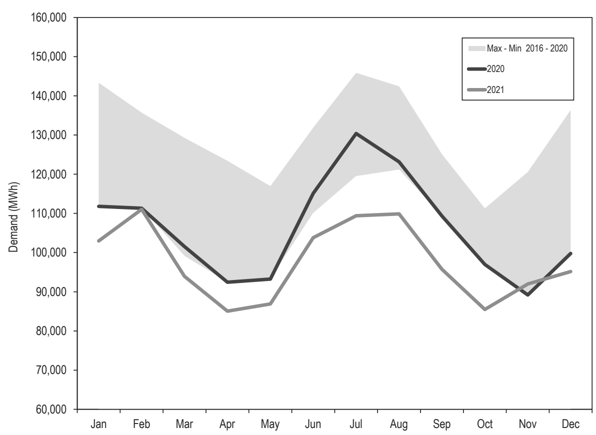
Table 3-10 Day-ahead hourly average demand and demand plus exports: 2001 through 2021

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,370	6,562	33,757	6,431	NA	NA	NA	NA
2002	42,305	10,161	42,413	10,208	26.8%	54.8%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	6.0%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,716	114,827	18,872	(21.5%)	(42.7%)	(21.4%)	(42.2%)
2016	127,374	21,513	130,808	21,803	14.1%	14.9%	13.9%	15.5%
2017	125,794	19,402	128,757	19,625	(1.2%)	(9.8%)	(1.6%)	(10.0%)
2018	110,091	19,521	112,885	19,724	(12.5%)	0.6%	(12.3%)	0.5%
2019	112,588	18,163	115,444	18,386	2.3%	(7.0%)	2.3%	(6.8%)
2020	106,209	18,972	109,506	19,270	(5.7%)	4.5%	(5.1%)	4.8%
2021	97,537	17,869	100,642	18,359	(8.2%)	(5.8%)	(8.1%)	(4.7%)

PJM Day-Ahead Monthly Average Demand

Figure 3-15 compares the day-ahead monthly average demand including decrement bids and up to congestion transactions in 2020 and 2021 with the historic five-year range.

Figure 3-15 Day-ahead monthly average demand plus exports: 2020 through 2021



Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for day-ahead and real-time demand in 2020 and 2021. The last two columns of Table 3-11 are day-ahead demand minus real-time demand. The first column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load. The second column is the total day-ahead demand less the total real-time demand. The data show the impact of the reduction in UTC bids on day-ahead demand.

Table 3-11 Day-ahead and real-time demand (MWh): 2020 and 2021

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2020	82,417	1,217	4,318	18,257	3,297	109,506	84,584	90,059	(950)	19,447
	2021	84,958	1,324	4,206	7,050	3,105	100,642	87,606	92,774	(1,324)	7,868
Median	2020	79,869	1,215	3,847	19,196	3,247	105,764	81,950	87,286	(866)	18,478
	2021	82,695	1,339	3,867	6,833	2,890	98,035	85,326	90,135	(1,292)	7,900
Standard Deviation	2020	15,356	248	2,101	5,908	753	19,270	16,016	16,233	(412)	3,037
	2021	15,109	273	1,808	2,787	1,047	18,359	15,725	16,485	(343)	1,874
Peak Average	2020	90,254	1,344	5,091	18,960	3,464	119,113	92,373	97,921	(774)	21,193
	2021	93,022	1,480	4,822	8,072	3,298	110,693	95,571	101,029	(1,070)	9,664
Peak Median	2020	87,768	1,369	4,670	19,883	3,408	113,946	89,399	94,731	(263)	19,215
	2021	90,401	1,508	4,530	7,870	3,061	107,544	92,729	97,940	(820)	9,604
Peak Standard Deviation	2020	14,448	252	2,189	5,866	780	18,850	15,400	15,757	(700)	3,093
	2021	13,959	222	1,774	2,664	1,143	16,669	14,889	15,769	(708)	900
Off-Peak Average	2020	75,519	1,106	3,637	17,639	3,151	101,050	77,729	83,140	(1,105)	17,911
	2021	77,876	1,187	3,665	6,153	2,936	91,816	80,610	85,524	(1,548)	6,292
Off-Peak Median	2020	73,429	1,115	3,243	18,490	3,126	98,821	75,553	80,963	(1,009)	17,858
	2021	75,817	1,221	3,317	5,806	2,762	89,149	78,721	83,528	(1,684)	5,621
Off-Peak Standard Deviation	2020	12,569	183	1,758	5,877	697	15,256	13,161	13,216	(409)	2,040
	2021	12,263	238	1,660	2,576	921	14,915	12,849	13,404	(348)	1,511

Figure 3-16 shows the average cleared volumes of day-ahead and real-time demand in 2021. The day-ahead demand includes day-ahead load, decrement bids, up to congestion transactions, and day-ahead exports. The real-time demand includes real-time load and real-time exports.

Figure 3-16 Day-ahead and real-time demand (Average hourly volumes): 2021

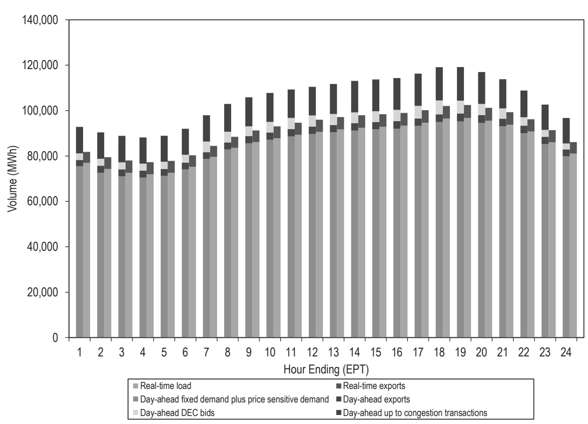
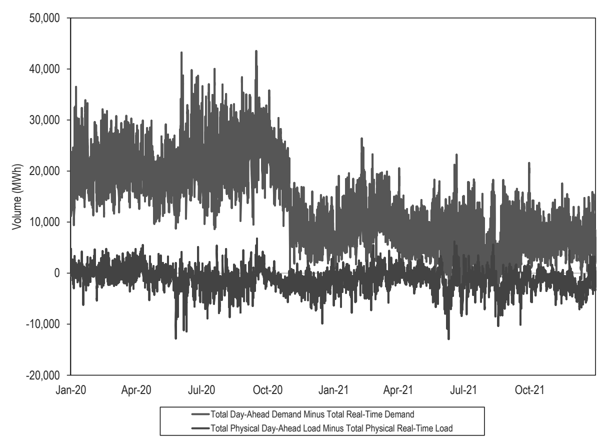


Figure 3-17 shows the difference between the day-ahead and real-time daily average demand in 2020 and 2021.

Figure 3-17 Difference between day-ahead and real-time daily average demand: 2020 through 2021



Market Behavior

Generator Offers

Generators indicate their availability for commitment and dispatch in the day-ahead market through their offers. Commitment availability status is economic, must run, or unavailable. Dispatch availability status is defined by the difference between the economic minimum and maximum output levels. PJM will clear units that select must run status in the offer in the day-ahead market up to their economic minimum MW regardless of economics. Units may set their economic minimum MW equal to their economic maximum MW, also termed block loaded, or at any point between economic minimum and economic maximum. Must run units may commit at economic minimum and permit the balance to be dispatchable or block load the full output of the unit. If units select economic commitment status, the day-ahead market will commit them based on their offers.

The Must Run column in Table 3-12 is the economic minimum MW of units offering with must run commitment status. The Eco Min column in Table 3-12 is the economic minimum MW of units offering with economic commitment status. The dispatchable range in Table 3-12 is the percent of MW offered by price range, between the economic minimum MW and economic maximum MW for all available units. Some units, like wind and solar, offer a dispatchable range in the day-ahead market although their availability in real time is determined by the presence of sun and wind rather than economics.

Units may designate all or a portion of their capacity as emergency MW. Table 3-12 shows that 0.8 percent of offered MW are emergency MW. In some cases, higher shares of emergency MW result from offer behavior that does not accurately represent the availability of the emergency MW in real time.

In the day-ahead market in 2021, 18.6 percent of MW were offered as must run, 27.0 percent of MW were offered as the economic minimum MW for dispatchable units, 53.6 percent of MW were offered as dispatchable, and 0.8 percent of MW were offered as emergency maximum MW.

Table 3-12 Dispatchable status of day-ahead energy offers: 2021

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) – $0	$0 – $25	$25 – $50	$50 – $75	$75 – $100	$100 – $200	$200 – $400	$400 – $600	$600 – $800	$800 – $1000	Emergency MW	Dispatchable Percent
CC	6.2%	29.1%	-0.0%	19.5%	32.2%	5.9%	2.2%	3.6%	0.8%	0.0%	0.0%	0.0%	0.5%	64.2%
CT	0.4%	51.1%	0.0%	1.6%	13.8%	11.8%	4.2%	10.1%	5.3%	0.3%	0.0%	0.0%	1.3%	47.1%
Diesel	0.0%	93.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.3%	0.0%	0.0%	0.0%	0.0%	6.3%
Hydro	85.2%	0.0%	13.3%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.8%
Nuclear	83.0%	6.5%	5.8%	4.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.6%
Solar	13.9%	0.1%	75.0%	7.7%	0.4%	1.5%	0.5%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	86.0%
Steam - Coal	18.7%	19.2%	0.0%	20.5%	23.9%	8.7%	2.4%	2.6%	0.2%	2.3%	0.0%	0.0%	1.4%	60.6%
Steam - Other	3.7%	20.2%	1.2%	2.6%	24.1%	15.4%	2.3%	20.4%	9.6%	0.0%	0.0%	0.0%	0.4%	75.7%
Wind	4.6%	0.7%	87.7%	4.8%	1.4%	0.6%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	94.7%
Other	17.7%	40.0%	3.8%	3.6%	7.7%	1.6%	1.3%	14.7%	5.4%	0.1%	0.0%	0.0%	3.9%	38.3%
All Units	18.6%	27.0%	2.7%	12.0%	20.7%	7.5%	2.3%	5.7%	2.3%	0.5%	0.0%	0.0%	0.8%	53.6%

Hourly Offers and Intraday Offer Updates

All participants may make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Table 3-13 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In 2021, an average of 326 units per day made hourly offers, an increase of 16 units from 2020. In 2021, 437 units opted in for intraday offer updates, an increase of 39 units from 2020. In 2021, an average of 130 units made intraday offer updates each day, a decrease of one unit from 2020.

Table 3-13 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: 2020 and 2021

	Fuel Type	2020	2021	Difference
Hourly Offers	Natural Gas	291	303	12
	Other Fuels	19	23	4
	Total	310	326	16
Opt In	Natural Gas	348	364	16
	Other Fuels	50	73	23
	Total	398	437	39
Intraday Offer Updates	Natural Gas	127	123	(4)
	Other Fuels	4	7	3
	Total	131	130	(1)

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[28] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement.

Solar, wind, landfill gas, hydro and batteries can satisfy the must offer requirement by self scheduling or offering as dispatchable. There is no defined amount of capacity that these resources must offer. The must offer requirement is thus not applied to these intermittent resource types and compliance is not enforceable.

The current enforcement of the ICAP must offer requirement is inadequate.[29] The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

Resources are required to submit their available capacity in three different systems. Resources are required to make offers in the energy market. Resources are required to report outages in the Dispatch Application Reporting Tool (eDART) in advance or in real time. Resources are required to report outages in the Generator Availability Data System (eGADS) after the fact. The three applications are not linked in a systematic way to ensure consistency.

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are never reported as outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORd.

The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate.

The MMU recommends that intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources.

Table 3-14 shows average hourly MW, for each month, that violated the ICAP must offer requirement in 2021. On average for all hours, 1,550 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 2,963 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that triggered scarcity pricing in 2021 and larger than most supply contingencies that led to synchronized reserve events in 2021.

Table 3-14 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: 2021

Month	90th Percentile	Average	10th Percentile
Jan-21	958	494	97
Feb-21	1,139	683	242
Mar-21	2,194	1,491	554
Apr-21	5,160	4,040	2,772
May-21	3,347	2,575	1,986
Jun-21	1,682	1,069	487
Jul-21	2,570	1,699	796
Aug-21	2,224	1,440	754
Sep-21	1,465	915	433
Oct-21	1,488	872	391
Nov-21	2,580	1,784	894
Dec-21	2,554	1,501	496
2021	2,963	1,550	416

The outage data reported in eGADS do not exactly match the energy market data submitted in Markets Gateway. For example, economic maximum MW levels submitted in Markets Gateway that reflect expected ambient conditions (including ambient derates) can be inconsistent with the maximum capability submitted in eGADS. Another example is the start and end times of planned outages in the shoulder months. In many situations units are derated in Markets Gateway to reflect an upcoming planned outage for which the unit must ramp down over an extended period but in eGADS the outage start time is not reported until the unit is completely unavailable. These differences can result in units not meeting their ICAP must offer requirement.

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource

28 OA Schedule 1 § 1.10.1A(d).

29 PJM compares the data submitted in eDART to the data submitted in Markets Gateway using the eDART Gen Checkout. Generators are supposed to acknowledge their Gen Checkout reports. Manual 10 and the eDART User Guide do not specify what acknowledging the Gen Checkout report means, any requirements to acknowledge the Gen Checkout report or any consequences for not doing so. Gen Checkout is also only triggered if generators fail by more than defined thresholds.

can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals emergency maximum MW. The PJM market rules allow generators to include emergency maximum MW as part of ICAP offered in the capacity market.[30]

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[31]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[32] Capacity resources should offer their full output in the energy market and subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation. The capacity performance rules in the capacity market provide incentives for such output during PAI.

Table 3-15 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, 10 percent of hours in December 2021 had maximum emergency MW greater than or equal to 6,428 MW while 10 percent of hours in December 2021 had maximum emergency MW less than 1,822 MW. The hourly average, in 2021, was 2,358 MW offered as maximum emergency, 4.9 percent lower than in 2020. The increase in maximum emergency MW in December was mainly due to coal availability, consumables inventory shortages and environmentally limited units.

30 See 151 FERC ¶ 61,208 at P 476 (2015).
31 OA Schedule 1 § 1.10.1A(d).
32 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

Table 3-15 Maximum emergency MW by month: 2021

Month	90th Percentile	Average	10th Percentile
Jan-21	2,966	2,310	1,778
Feb-21	2,887	2,304	1,765
Mar-21	2,999	2,262	1,638
Apr-21	2,678	2,049	1,556
May-21	2,345	1,793	1,306
Jun-21	2,737	1,985	1,517
Jul-21	4,430	3,124	1,747
Aug-21	4,053	2,724	1,664
Sep-21	2,737	2,170	1,539
Oct-21	2,222	1,802	1,473
Nov-21	2,540	1,858	1,366
Dec-21	6,428	3,866	1,822
2021	3,492	2,358	1,535

Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared.

The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021.[33]

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in 2021. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[34] Table 3-16 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-16 shows that 28.0 percent of unit hours for units that failed the TPS test were committed on price-based schedules that were less flexible than their cost-based schedules. For effective market power mitigation there would be zero units that fail the TPS test committed with parameters less flexible than their cost-based schedules.

Table 3-16 Parameter mitigation for units failing TPS test: 2021

Day-ahead Commitment For Units That Failed TPS Test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	27,791	28.0%
Committed on price schedule as flexible as cost	7,668	7.7%
Total committed on price schedule without parameter limits	35,459	35.7%
Committed on cost (cost capped)	63,230	63.7%
Committed on price PLS	557	0.6%
Total committed on PLS schedules (cost or price PLS)	63,787	64.3%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in regions where a cold weather alert or a hot weather alert was declared in 2021. PJM declared cold weather alerts on six days and hot weather alerts on 23 days in 2021.[35] The analysis includes units with technologies that are subject to parameter limits, with a CP commitment, in the zones where the cold or hot weather alerts were declared. Table 3-17 shows that 32.6 percent of unit hours during weather alerts in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.[36] For effective market power mitigation there would be zero units committed during cold and hot weather alerts with parameters less flexible than their price PLS schedules.

Table 3-17 Parameter mitigation during weather alerts: 2021

Day-ahead Commitment During Hot And Cold Weather Alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	35,981	32.6%
Committed on price schedule as flexible as PLS	6,186	5.6%
Total committed on price schedule without parameter limits	42,167	38.2%
Committed on cost (cost capped)	2,367	2.1%
Committed on price PLS	65,782	59.6%
Total committed on PLS schedules (cost or price PLS)	68,149	61.8%

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The best solution to the use of inflexible parameters is to require the use of flexible parameters in all offers at all times for capacity resources. Capacity resources are paid to be flexible but that payment will not result in flexible

33 See 175 FERC ¶ 61,231 (2021).
34 Nuclear, wind, solar and hydro units are not subject to parameter limits.
35 *2021 State of the Market Report for PJM* Volume2, Section 3: Energy Market, at Emergency Procedures.
36 Nuclear, wind, solar and hydro units are not subject to parameter limits.

offers in the energy market, the only place it matters, unless there are explicit requirements that energy offers from capacity resources incorporate that flexibility.

If flexible parameters are not required at all times, the use of flexible parameters should be required whenever a unit fails the TPS test and whenever the system is facing emergency conditions. This would require that PJM apply the full set of approved unit specific parameters to a resource that offers any inflexible parameter under these conditions. The selection of the lowest cost offer, based on the financial parameters, would follow the application of PLS parameters.

Currently, PJM commits units on either a cost-based or a price-based schedule. For example, selecting a price-based schedule means selecting the combination of all the operating and financial parameters of such schedule. The financial parameters and the operating parameters must be addressed separately. This approach would simplify the schedule structure implemented in PJM and would allow PJM to effectively mitigate inflexible operating parameters.

The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times.

The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. PJM would separately mitigate the operating parameters and the financial parameters of the offers (incremental offer, startup cost, and no load cost).[37]

Parameter Limits

Beginning June 1, 2020, all capacity resources, including resources in FRR capacity plans, are capacity performance resources. The unit specific parameter limits for capacity performance resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. However, the tariff currently does not make it clear what parameter limit values are applicable for resources without a capacity commitment. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance resources by submitting supporting documentation which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for boiler based steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and a best practices equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited

37 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.

schedules.[38] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-18 shows, for the delivery year beginning June 1, 2021, the number of units that submitted and had approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM.

Table 3-18 Adjusted unit specific parameter limit statistics: 2021/2022 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	126	40	24.1%
Frame CT	171	102	37.4%
Combined Cycle	87	32	26.9%
Reciprocating Internal Combustion Engines	68	4	5.6%
Solid Fuel NUG	35	6	14.6%
Oil and Gas Steam	8	13	61.9%
Subcritical Coal Steam	7	57	89.1%
Supercritical Coal Steam	3	38	92.7%
Pumped Storage	8	0	0.0%

Real-Time Values

The Commission rejected PJM's proposed revisions to add RTV rules to the tariff in an order issued on May 28, 2021. In its order, the Commission recognized that RTVs can be used to exercise market power by withholding generation and avoiding market power mitigation.[39]

The real-time values submittal process was never defined in the PJM Operating Agreement. The process was defined only in PJM Manual 11. While there are a number of options for providing real-time unit status to PJM operators, PJM created a mechanism for the submission of such values called real-time values (RTVs). Unlike parameter exceptions, the use of real-time values made a unit ineligible for make whole payments, unless the market seller could justify such operation based on an actual constraint.[40] In the case of the notification time parameter, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the unit being committed, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

PJM's proposed RTV mechanism was rejected by the Commission because it would weaken the existing market power mitigation rules including parameter limited schedules.[41]

Beginning August 1, 2021, PJM provided guidance to market sellers that it would no longer accept real-time value submissions that were based on economic reasons, such as due to choosing not to staff a unit. In its order to show cause issued on June 17, 2021, the Commission stated its concern that "the PJM Tariff appears to be unjust and unreasonable because it fails to contain provisions governing what happens if a seller is unable to meet its unit-specific parameters in real time".[42] In its response to the Commission's order, PJM proposed tariff updates to allow generators to submit temporary exceptions during the operating day.[43] These rules require market sellers to justify that the request is based on a physical and actual constraint by submitting supporting documentation within three business days, consistent with the existing temporary parameter exception process. However, the September 15th Response proposes no consequences to market sellers who do not adhere to the proposed tariff defined rules on what is considered a valid justification for temporary exceptions.

Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and economically or physically withholds to decrease the likelihood of commitment, are compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses temporary parameter exceptions or RTVs to communicate the longer time to start to

38 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx>.
39 175 FERC ¶ 61,171 (2021).
40 See OA Schedule 1 § 3.2.3(e).
41 175 FERC ¶ 61,171 at P 36 (2021).
42 175 FERC ¶ 61,231 at P 17 (2021).
43 PJM. "Answer of PJM Interconnection LLC," Docket No. EL21-78 (September 15, 2021)("September 15th Response").

PJM, the unit's actual parameters are not recognized as inconsistent with its obligations as a capacity resource, not reflected in forced outages, and not reflected in eligibility for uplift payments. The market seller is able to withhold the unit in the energy market with no defined consequence, while other similarly situated units incur the costs associated with meeting their obligations. Such withholding is an exercise of market power. If market sellers instead represent that they are able to meet the time to start parameters, but the unit is not staffed or the unit is not equipped with remote start capability to meet its unit specific limits, there is no defined consequence for misrepresenting the unit's capability. In its September 15 Response, PJM proposes no explicit defined penalties for such behavior.

Units that override their turn down ratio (economic maximum divided by economic minimum) either use Real Time Values or PJM's fixed gen flag, which functions identically to a real-time value.[44] These resources operate on their parameter limited schedules but override their output limit parameters with no consequence. The only difference between a Real Time Value to override the turn down ratio parameter and the fixed gen flag is that the fixed gen resources receive uplift payments. These resources receive inefficient levels of uplift payments when they have market power. The September 15 Response does not address unstaffed units that refuse to meet their notification time or units that refuse to perform to their turn down ratio parameter by using fixed gen.

There are two options to address the real-time exceptions issue. The immediate option is to clearly define acceptable and unacceptable reasons for requesting a real-time exception. In the case of unacceptable reasons, the unit would not be paid a portion of its otherwise applicable capacity market revenues, e.g. the daily value, if it included the modified parameter values in its offer. The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint.

The better option, consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, is to not pay any capacity resources an appropriate portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that Capacity Performance resources are paid for their capacity only when it meets their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.[45]

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[46] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[47] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[48]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners

44 PJM Markets Gateway User Guide, Section 6.9: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 41, <https://www.pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.

45 *See* Monitoring Analytics LLC, "Real-Time Values," presented at the Markets Implementation Committee Special Session (October 7, 2020) at 12, which can be accessed at <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201007/20201007-item-06b-real-time-values-imm.ashx>.

46 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).

47 *Id* at P 439.

48 *Id* at P 440.

to establish unit parameters based on nonphysical limits, the June 9th Order weakened the incentives for units to be flexible and weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The fact that a contract may be entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome or that such a contract can reasonably impose costs on customers who were not party to the contract. The actual contractual terms are a function of the incentives and interests of the parties, who may be affiliates or have market power. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order will increase energy market uplift payments substantially. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market reference resource used for the Cost of New Entry (CONE) calculation for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the reference resource are expected to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and recently, during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. Table 3-19 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In 2021, there were 61 units in PJM, with a total installed capacity of 7,514 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions. The increase in the number of requests for 24 hour minimum run times in 2021, was caused by increased issuance of limits imposed by pipelines in the Western Region of PJM, including summer and winter months.

Table 3-19 Units with 24 hour minimum run times due to gas pipeline restrictions: 2017 through 2021

Year	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2017	20	3,216
2018	25	3,627
2019	37	5,616
2020	13	3,873
2021	61	7,513

Key parameters like startup and notification time were not included in the PLS matrix in 2017 and prior periods, even though other parameters were subject to parameter limits. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines.

The MMU observed instances when generators submitted temporary parameter exceptions based on claimed pipeline constraints even though these constraints are based on the nature of the transportation service that the generator procured from the pipeline. In some instances, generators requested temporary exceptions based on ratable take requirements stated in pipeline tariffs, even though the requirement is not enforced by the pipelines on a routine basis. If a unit were to be dispatched uneconomically using the inflexible parameters, the unit would receive make whole payments based on these temporary exceptions. The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced or on inferior transportation service chosen by the generator.

Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market, and such offers and bids may be marginal.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[49] Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion transaction bidding.[50] Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-18 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2021.

49 162 FERC ¶ 61,139 (2018).
50 Prior to November 1, 2012, market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "OASIS-Source-Sink-Link.xls,"<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Figure 3-18 Day-ahead aggregate supply curves: 2021 example day

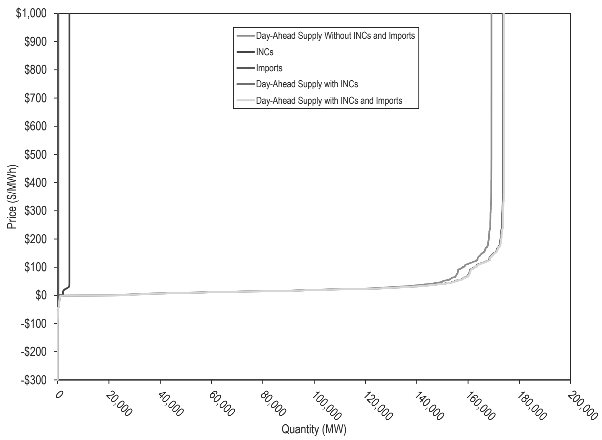


Table 3-20 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2020 and 2021. The hourly average submitted increment offer MW decreased by 12.1 percent and cleared increment MW decreased by 4.5 percent in 2021 compared to 2020. The hourly average submitted decrement bid MW increased by 12.0 percent and cleared decrement MW decreased by 2.4 percent in 2021 compared to 2020.

Table 3-20 Average hourly number of cleared and submitted INCs and DECs by month: January 2020 through December 2021

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2020	Jan	2,684	6,395	261	1,063	2,547	5,856	187	662
2020	Feb	2,544	7,043	233	1,046	2,990	6,653	222	702
2020	Mar	2,435	7,119	258	1,069	3,203	7,688	251	762
2020	Apr	2,655	7,738	299	1,167	3,400	8,312	261	840
2020	May	2,695	6,931	254	1,050	4,361	8,257	307	814
2020	Jun	2,353	7,185	235	1,011	5,140	9,843	404	1,083
2020	Jul	2,247	6,936	252	1,071	5,515	11,233	436	1,293
2020	Aug	1,915	6,084	209	973	5,148	10,165	451	1,217
2020	Sep	2,472	6,486	254	1,150	5,217	9,414	468	1,156
2020	Oct	2,492	6,086	309	1,084	4,884	9,696	392	1,229
2020	Nov	2,505	7,000	277	1,125	4,612	9,570	335	1,037
2020	Dec	2,141	5,911	241	974	4,746	10,450	321	1,190
2020	Annual	2,427	6,737	257	1,065	4,318	8,937	337	1,000
2021	Jan	2,208	6,221	259	1,068	3,916	10,076	297	1,194
2021	Feb	2,078	5,476	264	972	5,123	11,556	280	1,303
2021	Mar	2,838	6,524	273	947	4,406	10,063	280	1,149
2021	Apr	3,053	6,998	297	974	3,569	9,188	223	928
2021	May	2,431	6,036	259	885	3,415	8,363	187	862
2021	Jun	1,898	5,290	180	726	4,971	10,854	197	1,024
2021	Jul	2,244	5,797	211	820	3,810	9,054	165	842
2021	Aug	1,788	4,944	202	816	4,016	9,483	182	1,032
2021	Sep	2,226	5,984	252	899	4,080	10,290	276	1,214
2021	Oct	1,993	5,465	294	956	4,079	10,372	308	1,315
2021	Nov	2,636	6,324	344	1,074	3,812	9,446	304	1,224
2021	Dec	2,344	5,813	271	895	5,354	11,290	369	1,191
2021	Annual	2,312	5,907	259	919	4,206	9,991	256	1,105

Table 3-21 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2020 and 2021. The hourly average submitted up to congestion bid MW decreased by 58.2 percent and cleared up to congestion bid MW decreased by 61.4 percent in 2021 compared to 2020.

Table 3-21 Average hourly cleared and submitted up to congestion bids by month: January 2020 through December 2021

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2020	Jan	19,106	37,533	1,127	2,087
2020	Feb	19,415	40,281	1,100	2,133
2020	Mar	19,513	40,998	990	1,970
2020	Apr	18,267	37,298	955	1,859
2020	May	18,028	41,503	1,122	2,425
2020	Jun	23,038	59,520	1,403	2,726
2020	Jul	21,014	64,376	1,227	2,539
2020	Aug	22,478	63,368	1,159	2,306
2020	Sep	22,900	65,866	1,136	2,315
2020	Oct	19,587	55,904	933	1,957
2020	Nov	8,667	21,141	578	1,053
2020	Dec	7,156	17,968	526	942
2020	Annual	18,257	45,501	1,021	2,026
2021	Jan	7,277	20,412	546	1,062
2021	Feb	10,354	23,732	691	1,227
2021	Mar	8,776	24,571	548	1,087
2021	Apr	6,770	21,293	495	1,033
2021	May	6,976	20,674	585	1,164
2021	Jun	7,163	17,808	621	1,132
2021	Jul	6,743	16,386	572	1,041
2021	Aug	5,366	13,542	435	857
2021	Sep	6,659	16,579	471	1,138
2021	Oct	5,421	15,732	414	1,071
2021	Nov	6,761	18,741	490	1,106
2021	Dec	6,629	19,107	503	1,081
2021	Annual	7,050	19,014	530	1,082

Table 3-22 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2020 through December 2021. In 2021, the average hourly submitted import transaction MW decreased by 4.1 percent and the average hourly cleared import transaction MW decreased by 13.7 percent compared to 2020. In 2021, the average hourly submitted and cleared export transaction MW decreased by 5.2 and 5.8 percent compared to 2020.

Table 3-22 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2020 through December 2021

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2020	Jan	427	445	5	6	3,034	3,041	28	28
2020	Feb	324	346	4	5	2,737	2,742	29	29
2020	Mar	254	269	3	4	3,084	3,085	27	27
2020	Apr	173	188	2	3	3,057	3,062	25	25
2020	May	207	231	3	4	3,075	3,080	23	23
2020	Jun	159	152	2	2	3,782	3,798	31	31
2020	Jul	83	112	2	2	3,907	3,922	31	31
2020	Aug	100	128	2	2	3,909	3,920	29	29
2020	Sep	118	115	2	2	3,424	3,448	28	28
2020	Oct	171	164	2	2	3,268	3,231	26	26
2020	Nov	189	199	2	2	3,158	3,182	32	32
2020	Dec	173	180	2	2	3,106	3,113	31	31
2020	Annual	215	223	3	3	3,298	3,304	28	28
2021	Jan	389	408	4	4	2,854	2,862	30	30
2021	Feb	267	285	3	4	4,581	4,658	41	42
2021	Mar	250	266	2	3	2,493	2,542	27	28
2021	Apr	214	249	3	3	2,364	2,376	24	24
2021	May	217	268	2	3	2,255	2,279	21	21
2021	Jun	155	177	2	2	3,463	3,489	30	30
2021	Jul	139	180	2	3	3,690	3,713	32	33
2021	Aug	116	158	2	3	3,619	3,641	31	31
2021	Sep	108	136	2	2	3,231	3,251	30	31
2021	Oct	103	133	2	3	2,478	2,513	24	25
2021	Nov	169	189	3	3	2,307	2,314	20	20
2021	Dec	118	135	2	2	4,033	4,055	32	33
2021	Annual	185	214	2	3	3,105	3,132	28	29

Table 3-23 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in 2020 and 2021. The frequency of marginal up to congestion transactions deceased significantly in November 2020, due to decreased UTC activity beginning November 1, 2020, when FERC required UTCs to pay uplift.[51]

Table 3-23 Type of day-ahead marginal resources: 2020 and 2021

	2020						2021					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	27.7%	0.1%	44.7%	10.6%	16.9%	0.0%	23.1%	0.1%	35.7%	24.2%	16.9%	0.0%
Feb	20.7%	0.1%	48.5%	12.5%	18.2%	0.0%	20.3%	0.4%	45.1%	23.1%	11.1%	0.0%
Mar	19.5%	0.0%	52.2%	14.7%	13.6%	0.0%	18.9%	0.1%	33.9%	26.5%	20.6%	0.0%
Apr	18.2%	0.0%	49.3%	16.6%	15.9%	0.0%	19.4%	0.2%	34.4%	21.6%	24.5%	0.0%
May	16.6%	0.1%	55.2%	15.2%	13.0%	0.0%	20.6%	0.2%	35.5%	24.5%	19.1%	0.0%
Jun	14.1%	0.0%	60.8%	15.5%	9.6%	0.0%	21.3%	0.2%	35.8%	30.4%	12.3%	0.0%
Jul	11.8%	0.1%	57.4%	20.4%	10.3%	0.0%	17.6%	0.3%	39.4%	28.8%	13.8%	0.0%
Aug	10.5%	0.0%	55.3%	24.9%	9.2%	0.0%	18.4%	0.5%	37.2%	30.5%	13.4%	0.0%
Sep	13.1%	0.1%	54.8%	21.9%	10.1%	0.0%	18.5%	0.5%	30.6%	29.5%	20.9%	0.0%
Oct	14.7%	0.2%	58.2%	15.0%	12.0%	0.0%	18.3%	0.4%	32.7%	30.0%	18.4%	0.0%
Nov	21.0%	0.1%	27.6%	27.1%	24.2%	0.0%	18.8%	0.2%	32.5%	26.9%	21.5%	0.0%
Dec	20.8%	0.2%	32.7%	30.7%	15.5%	0.0%	19.7%	0.2%	32.5%	29.6%	18.0%	0.0%
Annual	16.5%	0.1%	51.4%	18.8%	13.2%	0.0%	19.5%	0.3%	35.2%	27.1%	17.9%	0.0%

51 172 FERC ¶ 61,046 (2020).

Figure 3-19 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through December 2021.

Figure 3-19 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through December 2021

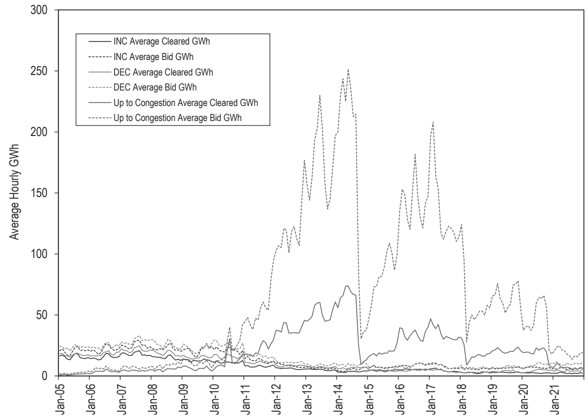
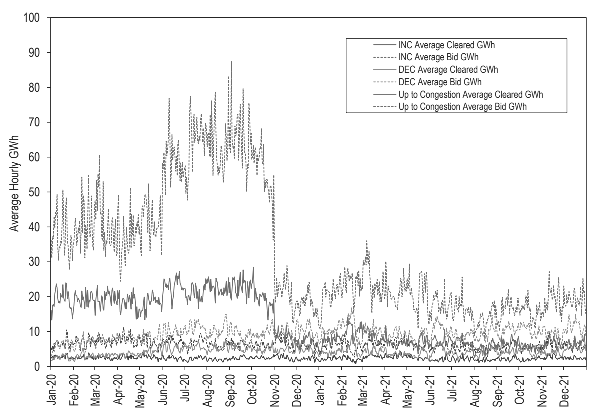


Figure 3-20 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2020 through December 2021.

Figure 3-20 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2020 through December 2021



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers that primarily take physical positions in PJM markets. Financial entities include banks and hedge funds that primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-24 shows, in 2020 and 2021, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-24 INC and DEC bids and cleared MWh by type of parent organization (MWh): 2020 and 2021

	2020				2021			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	119,754,941	87.1%	47,765,574	80.7%	126,426,159	90.9%	47,510,462	83.3%
Physical	17,815,214	12.9%	11,396,875	19.3%	12,726,137	9.1%	9,501,196	16.7%
Total	137,570,155	100.0%	59,162,450	100.0%	139,152,296	100.0%	57,011,658	100.0%

Table 3-25 shows, in 2020 and 2021, the total up to congestion bid and cleared MWh by type of parent organization.

Table 3-25 Up to congestion transactions by type of parent organization (MWh): 2020 and 2021

	2020				2021			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	354,265,533	88.6%	140,580,450	87.7%	148,844,114	89.4%	52,954,329	85.7%
Physical	45,411,729	11.4%	19,789,656	12.3%	17,716,432	10.6%	8,804,102	14.3%
Total	399,677,262	100.0%	160,370,106	100.0%	166,560,546	100.0%	61,758,431	100.0%

Table 3-26 shows, in 2020 and 2021, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-26 Import and export transactions by type of parent organization (MWh): 2020 and 2021

		2020		2021	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	12,513,761	41.1%	11,112,618	38.8%
	Physical	17,908,057	58.9%	17,559,321	61.2%
	Total	30,421,818	100.0%	28,671,939	100.0%
Real-Time	Financial	16,827,395	30.8%	15,123,148	28.7%
	Physical	37,727,552	69.2%	37,657,273	71.3%
	Total	54,554,947	100.0%	52,780,421	100.0%

Table 3-27 shows increment offers and decrement bids by top 10 locations in 2020 and 2021.

Table 3-27 Virtual offers and bids by top 10 locations (MWh): 2020 and 2021

2020					2021				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
MISO	INTERFACE	58,107	8,624,237	8,682,344	MISO	INTERFACE	142,869	7,171,196	7,314,066
WESTERN HUB	HUB	723,568	2,699,364	3,422,932	WESTERN HUB	HUB	986,937	2,038,390	3,025,327
AEP-DAYTON HUB	HUB	383,865	1,423,100	1,806,965	LINDENVFT	INTERFACE	52,287	1,839,732	1,892,019
BGE_RESID_AGG	RESIDUAL METERED EDC	295,127	1,340,188	1,635,315	DOM_RESID_AGG	RESIDUAL METERED EDC	148,177	1,638,788	1,786,965
DOM_RESID_AGG	RESIDUAL METERED EDC	202,235	1,240,902	1,443,137	BGE_RESID_AGG	RESIDUAL METERED EDC	209,818	1,171,638	1,381,456
NYIS	INTERFACE	752,258	298,276	1,050,534	AEP-DAYTON HUB	HUB	336,156	1,031,997	1,368,153
NEW JERSEY HUB	HUB	548,816	400,685	949,501	NYIS	INTERFACE	646,968	695,336	1,342,305
PECO_RESID_AGG	RESIDUAL METERED EDC	666,172	242,847	909,019	N ILLINOIS HUB	HUB	454,626	666,150	1,120,776
LINDENVFT	INTERFACE	38,492	858,203	896,695	AEPOHIO_RESID_AGG	RESIDUAL METERED EDC	163,078	853,661	1,016,739
N ILLINOIS HUB	HUB	377,415	509,377	886,792	SOUTH	INTERFACE	374,908	561,226	936,134
Top ten total		4,046,055	17,637,179	21,683,234			3,515,824	17,668,116	21,183,940
PJM total		21,316,711	37,927,647	59,244,357			20,249,427	36,845,793	57,095,220
Top ten total as percent of PJM total		19.0%	46.5%	36.6%			17.4%	48.0%	37.1%

Table 3-28 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall gross revenues before operating reserve charges on each path in 2020 and 2021. While the total cleared MWh were much lower in 2021 compared to 2020, total revenues were higher in 2021. The NIPSCO Interface was eliminated effective June 1, 2020. The NORTHWEST Interface was eliminated effective October 1, 2020. Before the elimination of these interfaces, trades located at these two nodes were among the largest sources of revenue for up to congestion transactions in 2020.[52]

Table 3-28 Cleared up to congestion bids by top 10 source and sink pairs (MWh): 2020 and 2021

2020							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Revenue
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	3,744,340	$440,221	($168,360)	$271,862
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	3,669,318	$271,849	$380,008	$651,857
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	3,619,492	$2,009,727	($1,180,586)	$829,140
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	3,246,574	($1,176,606)	$2,582,692	$1,406,085
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	3,243,735	$2,212,629	($1,291,746)	$920,884
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,963,981	$562,153	($589,765)	($27,612)
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,891,427	($814,561)	$1,279,724	$465,163
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,004,395	$93,837	$382,023	$475,860
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,851,417	$1,029,251	($599,088)	$430,164
CHICAGO HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,833,368	($66,689)	$538,664	$471,975
Top ten total				29,068,045	$4,561,811	$1,333,566	$5,895,376
PJM total				161,264,539	($7,195,013)	$29,924,046	$22,729,033
Top ten total as percent of PJM total				18.0%	(63.4%)	4.5%	25.9%
2021							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MWh	Source Revenue	Sink Revenue	UTC Revenue
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	2,570,236	$1,244,132	$43,237	$1,287,369
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,553,735	$1,197,740	($50,913)	$1,146,826
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	1,211,566	($2,565,267)	$3,003,939	$438,672
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,192,820	$792,942	($13,947)	$778,996
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,099,374	$1,609,490	($394,058)	$1,215,432
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,019,303	($38,126)	$721,284	$683,159
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	985,039	($816,890)	$1,669,849	$852,959
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	790,447	$894,733	($485,537)	$409,197
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	701,779	$525,047	($18,313)	$506,734
COMED_RESID_AGG	HUB	AEPOHIO_RESID_AGG	AGGREGATE	693,387	$134,423	$182,197	$316,620
Top ten total				11,817,687	$2,978,224	$4,657,739	$7,635,963
PJM total				61,758,431	$10,767,990	$37,827,349	$48,595,339
Top ten total as percent of PJM total				19.1%	27.7%	12.3%	15.7%

52 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-29 shows the average daily number of source-sink pairs that were offered and cleared each month from January 2020 through December 2021. Since November 1, 2020, there has been a decrease in the average number of paths with submitted and cleared bids.

Table 3-29 Number of offered and cleared source and sink pairs: January 2020 through December 2021

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2020	Jan	1,658	1,942	1,523	1,857
2020	Feb	1,710	1,975	1,568	1,725
2020	Mar	1,789	2,013	1,591	1,832
2020	Apr	1,804	1,978	1,567	1,760
2020	May	1,913	2,126	1,681	1,900
2020	Jun	1,974	2,111	1,803	2,020
2020	Jul	1,886	2,085	1,749	1,970
2020	Aug	1,760	1,993	1,575	1,854
2020	Sep	1,656	1,851	1,498	1,641
2020	Oct	1,544	1,689	1,358	1,525
2020	Nov	1,306	1,497	1,203	1,387
2020	Dec	1,305	1,508	1,184	1,359
2020	Annual	1,692	1,897	1,525	1,736
2021	Jan	1,286	1,470	1,132	1,302
2021	Feb	1,303	1,514	1,210	1,449
2021	Mar	1,314	1,542	1,189	1,386
2021	Apr	1,309	1,559	1,146	1,388
2021	May	1,329	1,540	1,176	1,395
2021	Jun	1,291	1,412	1,161	1,289
2021	Jul	1,299	1,466	1,161	1,294
2021	Aug	1,403	1,622	1,221	1,469
2021	Sep	1,503	1,610	1,272	1,427
2021	Oct	1,461	1,567	1,212	1,349
2021	Nov	1,501	1,603	1,304	1,426
2021	Dec	1,421	1,582	1,216	1,345
2021	Annual	1,301	1,509	1,177	1,379

Table 3-30 and Figure 3-21 show total cleared up to congestion transactions and share of the top 10 up to congestion paths by transaction type (import, export, or internal) in 2020 and 2021. Total cleared up to congestion transactions decreased by 61.5 percent from 160.4 million MWh in 2020 to 61.8 million MWh in 2021. Internal up to congestion transactions in 2021 were 82.1 percent of all up to congestion transactions compared to 70.3 percent in 2020.

Table 3-30 Cleared up to congestion transactions and share of top 10 paths by type (MW): 2020 and 2021

	2020				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	14,985,749	8,011,106	6,146,761	25,124,751	54,268,367
PJM total (MW)	26,395,388	14,306,955	6,960,599	112,707,163	160,370,106
Top ten total as percent of PJM total	56.8%	56.0%	88.3%	22.3%	33.8%
PJM total as percent of all up to congestion transactions	16.5%	8.9%	4.3%	70.3%	100.0%
	2021				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,645,482	2,857,649	654,212	11,404,877	17,562,220
PJM total (MW)	5,212,311	5,026,300	805,093	50,714,726	61,758,431
Top ten total as percent of PJM total	50.8%	56.9%	81.3%	22.5%	28.4%
PJM total as percent of all up to congestion transactions	8.4%	8.1%	1.3%	82.1%	100.0%

Figure 3-21 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[53] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[54] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction. UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[55]

Figure 3-21 Monthly cleared up to congestion transactions by type (GWh): January 2005 through December 2021

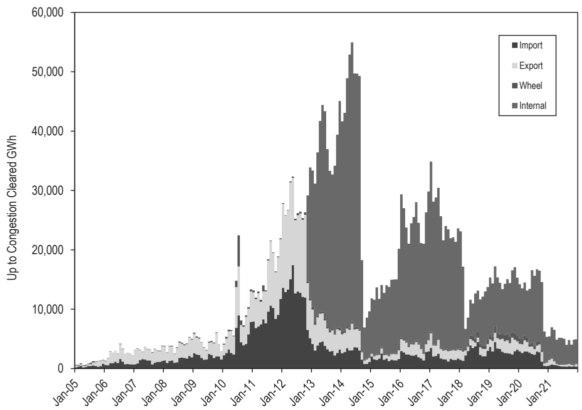
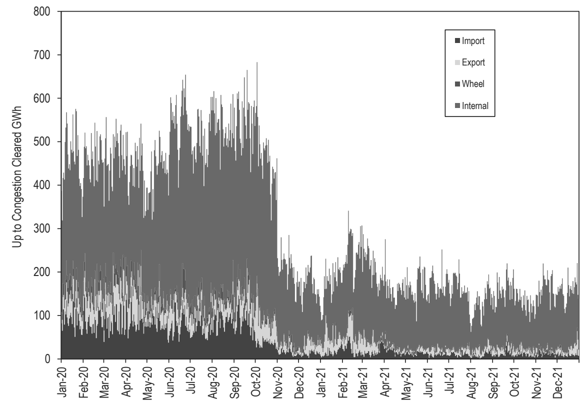


Figure 3-22 shows the daily cleared up to congestion GWh by transaction type from January 1, 2020 through December 31, 2021.

Figure 3-22 Daily cleared up to congestion transaction by type (GWh): January 2020 through December 2021



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[56]

A key assumption underlying the February 2018 order is that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.[57] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational

53 See 162 FERC ¶ 61,139 (2018).
54 *Id.*
55 See 172 FERC ¶ 61,046 (2020).

56 PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," Docket No. ER18-88, October 17, 2017 at 9–10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them…Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."
57 162 FERC ¶ 61,139 at PP 35–36 (2018) ("We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates.").

differences between day-ahead and real-time since the February 2018 order.

The assumption that modeling differences are averaged out over aggregate nodes does not hold for multiple nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For this reason, the MMU recommends eliminating UTC bidding at the following nodes: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when constraints are violated and transmission penalty factors are applied in the real-time energy market. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day ahead and real time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be in the tens to hundreds of dollars, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads resulting from systematic modeling and operational differences between day ahead and real time affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

The real-time average LMP in 2021 increased 84.8 percent from 2020, from $20.66 per MWh to $38.18 per MWh. The real-time load-weighted average LMP in 2021 increased 82.8 percent from 2020, from $21.77 per MWh to $39.78 per MWh.

The real-time load-weighted average LMP in 2021 was 49.1 percent higher than the real-time fuel-cost adjusted load-weighted average LMP in 2021. If fuel and emission costs in 2021 had been the same as in 2020, holding everything else constant, the load-weighted LMP would have been lower, $26.68 per MWh instead of the observed $39.78 per MWh.

The day-ahead average LMP in 2021 increased 85.8 percent from 2020, from $20.33 per MWh to $37.76 per MWh. The day-ahead load-weighted average LMP in 2021 increased 84.0 percent from 2020, from $21.40 per MWh to $39.37 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply curve.[58] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node

58 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2) at 19–27.

may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[59]

LMP may, at times, be set by transmission penalty factors, which exceed $1,000 per MWh. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Fast Start Pricing

PJM implemented fast start pricing in both the day-ahead and real-time markets on September 1, 2021. Fast start pricing employs a new LMP calculation called the pricing run. The pricing run LMP (PLMP) is now the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP). Unless otherwise specified, the LMP tables and figures show the PLMP for September 1, 2021, and after.

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously relaxing the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units meet the following conditions: Notification time plus start time are less than or equal to one hour; minimum run time is less than or equal to one hour; and units are online and running for PJM, not self-scheduled. This pricing method is intended to allow inflexible resources to set prices with their commitment costs per MWh added to their marginal costs.

DLMP and PLMP

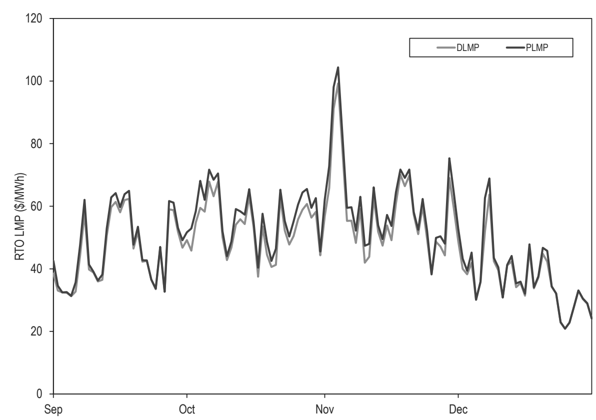
Table 3-31 shows the day-ahead and real-time monthly load-weighted average DLMP and PLMP since September 2021. The real-time load-weighted average PLMP was $52.20 per MWh for September 1, 2021, through December 31, 2021, which is 5.5 percent, $2.73 per MWh, higher than the real-time load-weighted average DLMP of $49.47 per MWh. The day-ahead load-weighted average PLMP was 0.3 percent, $0.15 per MWh, higher than day-ahead load-weighted average DLMP.

Table 3-31 Day-ahead and real-time load-weighted average DLMP and PLMP: September through December, 2021

	2021							
	Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Month	DLMP	PLMP	Difference	Difference Percent	DLMP	PLMP	Difference	Difference Percent
Sep	$46.00	$46.14	$0.13	0.3%	$47.73	$49.63	$1.90	4.0%
Oct	$57.86	$57.98	$0.12	0.2%	$54.53	$58.42	$3.89	7.1%
Nov	$60.76	$61.00	$0.24	0.4%	$59.27	$63.01	$3.74	6.3%
Dec	$37.74	$37.85	$0.11	0.3%	$37.37	$38.92	$1.55	4.2%
Sep-Dec	$50.30	$50.46	$0.15	0.3%	$49.47	$52.20	$2.73	5.5%

Figure 3-23 shows the real-time daily average DLMP and PLMP since September 2021.

Figure 3-23 Real-time daily average DLMP and PLMP: September through December, 2021



Fast start pricing affected the difference between DLMP and PLMP in real time more than in day ahead. Figure 3-24 shows the hourly difference between DLMP and PLMP for day-ahead and real-time since September 2021.

59 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

Figure 3-24 Hourly difference in DLMP and PLMP for day-ahead and real-time: September through December, 2021

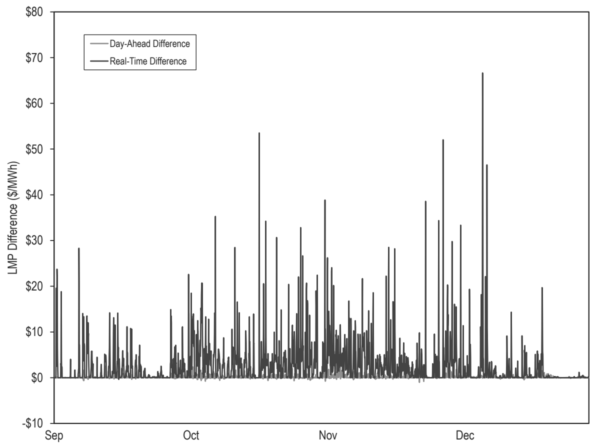


Figure 3-24 shows the hourly average load and LMP difference by hour of the day since September 2021. The difference between real-time DLMP and PLMP is highest at 7:00 (EPT) and 17:00 (EPT).

Figure 3-25 Hourly average load and LMP difference: September through December, 2021

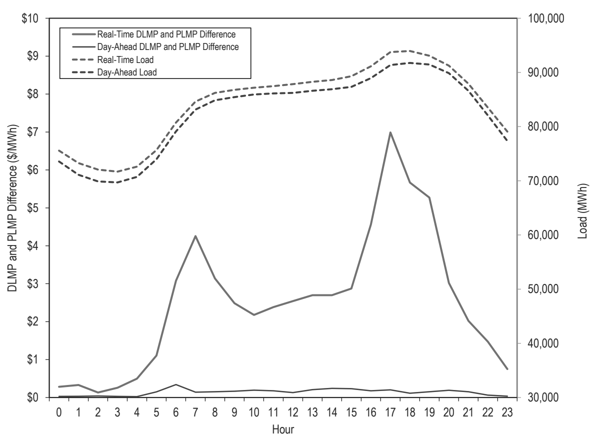


Table 3-32 shows the percent of total marginal units that are fast start units by unit type since September 2021.

Table 3-32 Fast start units as a percent of marginal units: September through December, 2021

	Pricing Run				Dispatch Run			
2021	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
Sep	6.7%	1.3%	0.0%	8.1%	2.2%	0.8%	0.0%	3.0%
Oct	11.1%	2.1%	0.0%	13.3%	3.2%	1.4%	0.0%	4.6%
Nov	11.3%	0.6%	0.0%	11.9%	3.2%	0.3%	0.0%	3.5%
Dec	4.4%	0.6%	0.1%	5.2%	1.4%	0.3%	0.2%	1.8%

Table 3-33 shows the difference in day-ahead and real-time zonal average DLMP and PLMP since September 2021. Fast start pricing had different impacts by zone. As a result of fast start pricing, the average increase in real-time prices in BGE was 5.6 percent, $3.12 per MWh, while the average increase in real-time prices in AECO was 3.8 percent, $1.48 per MWh.

Table 3-33 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): September through December, 2021

	2021 Sep - Dec							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Difference Percent	Average DLMP	Average PLMP	Difference	Difference Percent
ACEC	$38.65	$38.73	$0.08	0.2%	$38.53	$39.81	$1.28	3.3%
AEP	$50.44	$50.59	$0.15	0.3%	$49.58	$51.85	$2.27	4.6%
APS	$51.87	$52.03	$0.15	0.3%	$51.04	$53.28	$2.24	4.4%
ATSI	$50.68	$50.82	$0.14	0.3%	$49.23	$51.44	$2.21	4.5%
BGE	$57.58	$57.75	$0.18	0.3%	$55.73	$58.41	$2.67	4.8%
COMED	$43.11	$43.26	$0.15	0.4%	$41.87	$44.44	$2.57	6.1%
DAY	$53.18	$53.33	$0.15	0.3%	$52.28	$54.58	$2.31	4.4%
DUKE	$51.90	$52.06	$0.15	0.3%	$50.41	$52.66	$2.25	4.5%
DOM	$55.10	$55.26	$0.16	0.3%	$55.09	$57.58	$2.49	4.5%
DPL	$45.02	$45.15	$0.14	0.3%	$43.18	$45.64	$2.46	5.7%
DUQ	$50.02	$50.15	$0.14	0.3%	$48.86	$51.02	$2.17	4.4%
EKPC	$51.68	$51.83	$0.15	0.3%	$50.76	$53.01	$2.25	4.4%
JCPLC	$40.96	$41.05	$0.09	0.2%	$40.44	$41.97	$1.53	3.8%
MEC	$50.57	$50.69	$0.12	0.2%	$49.56	$51.45	$1.89	3.8%
OVEC	$50.41	$50.55	$0.15	0.3%	$49.57	$51.78	$2.21	4.5%
PECO	$39.09	$39.16	$0.07	0.2%	$38.85	$40.24	$1.39	3.6%
PE	$49.42	$49.56	$0.14	0.3%	$47.53	$49.32	$1.79	3.8%
PEPCO	$56.10	$56.28	$0.17	0.3%	$55.50	$58.15	$2.65	4.8%
PPL	$45.28	$45.39	$0.11	0.2%	$44.26	$46.00	$1.74	3.9%
PSEG	$40.98	$41.07	$0.09	0.2%	$40.56	$42.10	$1.54	3.8%
REC	$43.04	$43.13	$0.09	0.2%	$42.22	$43.89	$1.68	4.0%

Table 3-34 shows the difference in day-ahead and real-time average DLMP and PLMP for PJM hubs since September 2021.

Table 3-34 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): September through December, 2021

	2021 Sep - Dec							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Difference Percent	Average DLMP	Average PLMP	Difference	Difference Percent
AEP GEN HUB	$49.88	$50.03	$0.15	0.3%	$48.81	$51.01	$2.20	4.5%
AEP-DAYTON HUB	$49.92	$50.07	$0.15	0.3%	$48.73	$51.03	$2.30	4.7%
ATSI GEN HUB	$49.77	$49.91	$0.14	0.3%	$48.09	$50.27	$2.18	4.5%
CHICAGO GEN HUB	$42.40	$42.55	$0.15	0.4%	$40.83	$43.35	$2.52	6.2%
CHICAGO HUB	$43.40	$43.56	$0.15	0.4%	$42.19	$44.79	$2.60	6.2%
DOMINION HUB	$53.58	$53.74	$0.16	0.3%	$53.51	$55.90	$2.38	4.5%
EASTERN HUB	$44.18	$44.33	$0.15	0.3%	$42.61	$44.98	$2.36	5.5%
N ILLINOIS HUB	$43.10	$43.25	$0.15	0.4%	$41.82	$44.38	$2.56	6.1%
NEW JERSEY HUB	$40.55	$40.64	$0.09	0.2%	$40.16	$41.66	$1.50	3.7%
OHIO HUB	$49.55	$49.70	$0.15	0.3%	$48.17	$50.50	$2.33	4.8%
WEST INT HUB	$51.27	$51.42	$0.15	0.3%	$50.34	$52.61	$2.27	4.5%
WESTERN HUB	$51.99	$52.15	$0.16	0.3%	$50.71	$52.92	$2.21	4.4%

Table 3-35 shows the frequency of the real-time pricing interval differences in DLMP and PLMP by price range for PJM zones since September 2021.

Table 3-35 Real-time interval difference (dollars per MWh) in zonal DLMP and PLMP for September through December 2021

	2021 Sep - Dec									
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	1.6%	0.0%	0.5%	47.1%	46.0%	3.2%	1.1%	0.3%	0.1%
ACEC	0.0%	1.7%	0.3%	7.2%	47.8%	40.0%	2.1%	0.6%	0.2%	0.1%
AEP	0.0%	1.6%	0.0%	0.7%	47.3%	45.3%	3.4%	1.2%	0.3%	0.1%
APS	0.0%	1.6%	0.0%	0.9%	47.4%	44.8%	3.4%	1.3%	0.3%	0.1%
ATSI	0.0%	1.6%	0.0%	1.0%	47.3%	45.3%	3.1%	1.1%	0.3%	0.1%
BGE	0.0%	1.6%	0.1%	1.9%	47.3%	42.2%	4.4%	1.8%	0.4%	0.2%
COMED	0.0%	1.6%	0.0%	1.6%	47.6%	43.9%	3.4%	1.4%	0.3%	0.1%
DAY	0.0%	1.6%	0.0%	0.9%	47.4%	44.8%	3.5%	1.3%	0.3%	0.1%
DUKE	0.0%	1.6%	0.0%	0.8%	47.4%	45.0%	3.4%	1.2%	0.3%	0.1%
DOM	0.0%	1.6%	0.1%	1.3%	47.5%	43.4%	4.1%	1.5%	0.4%	0.1%
DPL	0.0%	1.6%	0.1%	10.8%	47.9%	33.5%	2.6%	2.6%	0.6%	0.3%
DUQ	0.0%	1.6%	0.0%	0.9%	47.4%	45.3%	3.2%	1.1%	0.3%	0.1%
EKPC	0.0%	1.6%	0.0%	1.0%	47.5%	44.8%	3.4%	1.2%	0.3%	0.1%
JCPLC	0.0%	1.6%	0.0%	3.4%	47.9%	43.9%	2.2%	0.7%	0.2%	0.1%
MEC	0.0%	1.6%	0.1%	3.1%	47.5%	42.0%	3.4%	1.5%	0.5%	0.1%
OVEC	0.0%	1.6%	0.0%	0.9%	47.5%	45.1%	3.3%	1.2%	0.3%	0.1%
PECO	0.0%	1.6%	0.0%	9.3%	47.8%	38.0%	2.2%	0.7%	0.2%	0.1%
PE	0.0%	1.7%	0.1%	1.0%	47.3%	45.5%	3.0%	1.0%	0.3%	0.1%
PEPCO	0.0%	1.6%	0.1%	1.8%	47.4%	42.3%	4.4%	1.8%	0.4%	0.2%
PPL	0.0%	1.6%	0.0%	2.8%	47.6%	43.7%	2.7%	1.0%	0.3%	0.1%
PSEG	0.0%	1.6%	0.0%	3.3%	47.8%	44.0%	2.2%	0.6%	0.2%	0.1%
REC	0.0%	1.6%	0.0%	2.2%	47.5%	45.3%	2.3%	0.7%	0.2%	0.1%

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[60]

PJM Real-Time Average LMP

Table 3-36 shows the real-time average LMP for 1998 through 2021.[61] The real-time average LMP in 2021 increased 84.8 percent from 2020, from $20.66 per MWh to $38.18 per MWh.

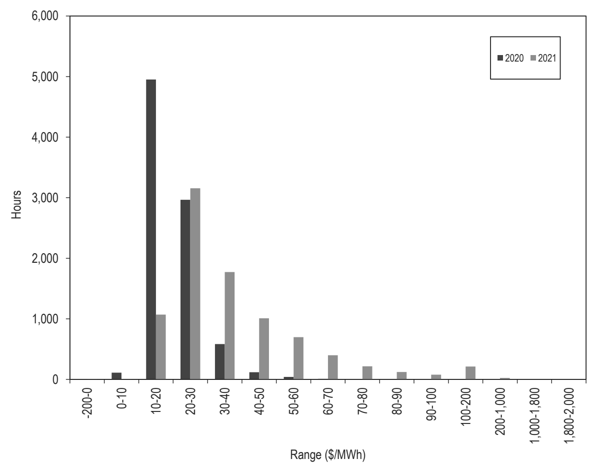
Table 3-36 Real-time average LMP (Dollars per MWh): 1998 through 2021

	Real-Time LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)
2014	$48.22	$34.46	$65.08	31.9%	6.8%	216.4%
2015	$33.39	$26.61	$27.80	(30.7%)	(22.8%)	(57.3%)
2016	$27.57	$24.10	$14.76	(17.4%)	(9.4%)	(46.9%)
2017	$29.42	$25.44	$17.40	6.7%	5.6%	17.9%
2018	$35.75	$28.28	$29.52	21.5%	11.2%	69.7%
2019	$26.02	$22.89	$21.19	(27.2%)	(19.1%)	(28.2%)
2020	$20.66	$18.35	$11.77	(20.6%)	(19.8%)	(44.4%)
2021	$38.18	$30.59	$26.37	84.8%	66.7%	124.0%

PJM Real-Time Average LMP Duration

Figure 3-26 shows the hourly distribution of the real-time average LMP in 2020 and 2021. There were 4,951 hours with an average LMP between $10 and $20 per MWh in 2020, but only 1,071 hours were in the same range in 2021. LMP did not exceed $80 per MWh in 2020, while there were 437 hours in 2021, 5.0 percent of hours, with an average LMP above $80 per MWh.

Figure 3-26 Distribution of real-time LMP: 2020 and 2021



Real-Time Load-Weighted Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted average LMP reflects the average real-time LMP paid for actual MWh consumed during a year. Load-weighted average LMP is the average of PJM hourly LMP, with each hourly LMP weighted by the PJM total hourly load.

PJM Real-Time Load-Weighted Average LMP

Table 3-37 shows the real-time load-weighted average LMP for 1998 through 2021. The real-time load-weighted average LMP in 2021 increased 82.8 percent from 2020, from $21.77 per MWh to $39.78 per MWh, the largest annual percent increase since the start of PJM markets in 1999, although not the largest dollar per MWh increase.

60 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

61 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

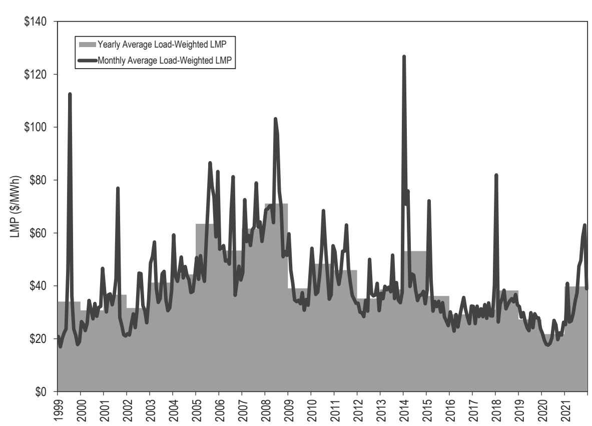
Table 3-37 Real-time load-weighted average LMP (Dollars per MWh): 1998 through 2021

	Real-Time Load-Weighted Average LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(31.9%)	(23.6%)	(59.2%)
2016	$29.23	$25.01	$16.12	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	6.0%	5.4%	19.9%
2018	$38.24	$29.55	$32.89	23.4%	12.1%	70.2%
2019	$27.32	$23.63	$23.12	(28.6%)	(20.0%)	(29.7%)
2020	$21.77	$19.07	$12.50	(20.3%)	(19.3%)	(45.9%)
2021	$39.78	$32.11	$27.72	82.8%	68.4%	121.8%

PJM Real-Time Monthly Load-Weighted Average LMP

Figure 3-27 shows the real-time monthly and yearly load-weighted average LMP for 1999 through 2021.

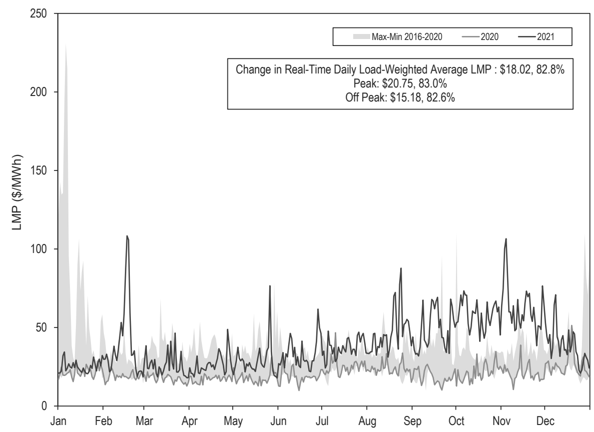
Figure 3-27 Real-time monthly and yearly load-weighted average LMP: 1999 through 2021



PJM Real-Time Daily Load-Weighted Average LMP

Figure 3-28 shows the real-time daily load-weighted average LMP in 2020 and 2021.

Figure 3-28 Real-time daily load-weighted average LMP: 2020 and 2021



PJM Real-Time Monthly Inflation Adjusted Load-Weighted Average LMP

Figure 3-29 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through December 2021.[62] Table 3-38 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for every year from 1998 through 2021. The PJM real-time inflation adjusted load-weighted average LMP in 2021 was the fifth lowest value since PJM real-time markets started on April 1, 1999 at $23.63 per MWh. The real-time inflation adjusted monthly load-weighted average LMP for April 2020 was the lowest monthly value since PJM markets started in April 1999 at $11.08 per MWh.

62 To obtain the inflation adjusted, monthly, load-weighted, average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed January 12, 2022)

Figure 3-29 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through December 2021

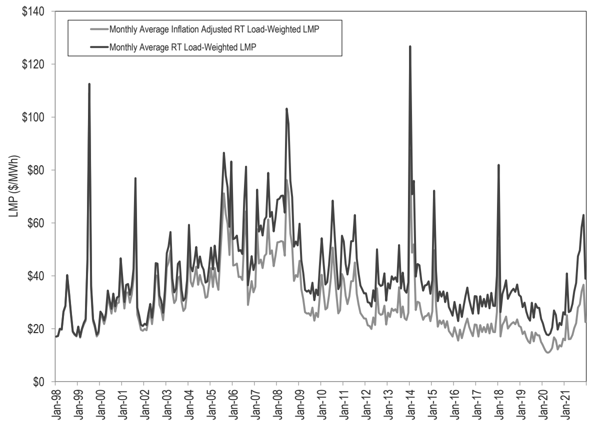


Table 3-38 Real-time load-weighted and inflation adjusted load-weighted average LMP: 1998 through 2021

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
1998	$24.16	$23.94
1999	$34.07	$33.04
2000	$30.72	$28.80
2001	$36.65	$33.45
2002	$31.60	$28.35
2003	$41.23	$36.24
2004	$44.34	$37.91
2005	$63.46	$52.37
2006	$53.35	$42.73
2007	$61.66	$48.06
2008	$71.13	$53.27
2009	$39.05	$29.46
2010	$48.35	$35.83
2011	$45.94	$33.01
2012	$35.23	$24.80
2013	$38.66	$26.82
2014	$53.14	$36.37
2015	$36.16	$24.69
2016	$29.23	$19.68
2017	$30.99	$20.43
2018	$38.24	$24.65
2019	$27.32	$17.28
2020	$21.77	$13.58
2021	$39.78	$23.63

Real-Time Dispatch and Pricing

In the first ten months of 2021, real-time dispatch and pricing were not temporally aligned. On November 1, 2021, PJM implemented a new real-time dispatch process that aligned the timing of dispatch and pricing in the real-time energy market. The PJM Real-Time Energy Market consists of a series of applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the ancillary services optimizer (ASO), real-time security constrained economic dispatch (RT SCED), and the locational pricing calculator (LPC).[63] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast at a future point in time, called the target time. Prior to 2021, on average, PJM operators approved more than one RT SCED solution per five minute target time to send dispatch signals to resources. In 2021, on average, PJM operators approved one RT SCED solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs every five minutes. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution, but LPC assigned the prices to a five minute interval that did not contain the target time of the RT SCED case it used. On October 15, 2020, PJM updated its pricing process to use an approved RT SCED solution that solves for the same target time as the end of each five minute pricing interval to calculate LMPs applicable for that five minute interval, although the SCED cases were still for 10 minutes ahead while the LPC cases were for each five minute interval. As a result, under the default timing of case approvals, resources followed the dispatch signal in the first five minutes after the RT SCED case approval and the corresponding pricing occurred five minutes after the same case approval, when resources were following a new dispatch signal. On November 1, 2021, PJM implemented changes to RT SCED that solved the energy dispatch case using a five-minute dispatch period, and ramped resources for five minutes to meet the load and reserve requirements at the end of each five minute period. The approved RT SCED solution that dispatched units for each five minute period was also used to calculate prices for the same five minute interval, aligning the prices with the concurrent dispatch signals.

63 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 117 (Nov. 1, 2021)

Table 3-39 shows, on a monthly basis in 2020 and 2021, the number of RT SCED case solutions, the number of solutions that were approved and the number and percent of approved solutions used in LPC. Until February 24, 2020, RT SCED was automatically executed every three minutes with operators having the ability to execute additional cases in between the automatically executed cases. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes. On June 22, 2020, PJM changed the RT SCED execution frequency to once every five minutes. PJM operators continue to have the ability to execute additional RT SCED cases. Prior to June 3, 2021, each execution of RT SCED produced three solutions, using three different levels of load bias. Beginning June 3, 2021, each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

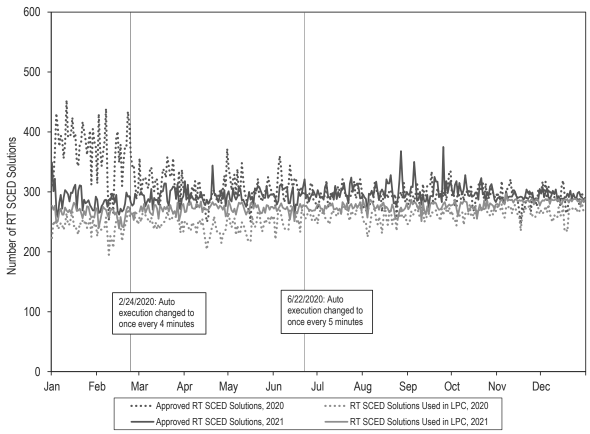
Table 3-39 shows that in 2021, 92.8 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 82.1 percent in 2020. The percent of approved solutions used for pricing increased in 2020 with the decrease in the frequency of executed RT SCED cases.

Figure 3-30 shows the daily number of RT SCED cases approved by PJM operators to send dispatch signals to resources and the subset of approved RT SCED cases that were used in LPC to calculate LMPs in 2020 and 2021, and the dates when the frequency of RT SCED auto execution was changed in 2020. Figure 3-30 shows that changing the auto execution frequency of RT SCED from once every three minutes to once every four minutes on February 24, 2020 and to five minutes on June 22, 2020 reduced the number of approved RT SCED cases used to send dispatch signals in 2020. This change in the frequency of approved solutions reduced the difference between the number of approved solutions and the number of solutions used in pricing in 2021 relative to 2020.

Table 3-39 RT SCED cases solved, approved and used in pricing: 2020 and 2021

	2020				2021			
Month	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	51,022	11,860	7,612	64.2%	31,395	9,022	8,276	91.7%
Feb	46,247	10,149	7,005	69.0%	30,489	7,888	7,308	92.6%
Mar	38,680	9,914	7,799	78.7%	32,456	9,069	8,372	92.3%
Apr	36,543	8,888	7,132	80.2%	29,586	8,798	8,220	93.4%
May	36,648	9,416	7,590	80.6%	30,438	9,124	8,468	92.8%
Jun	34,327	9,165	7,666	83.6%	46,184	8,847	8,133	91.9%
Jul	30,342	9,241	8,190	88.6%	47,792	9,291	8,513	91.6%
Aug	30,775	8,962	7,868	87.8%	47,580	9,326	8,459	90.7%
Sep	30,632	8,972	7,881	87.8%	46,899	9,088	8,270	91.0%
Oct	32,429	9,145	8,199	89.7%	46,707	9,333	8,538	91.5%
Nov	30,360	8,695	8,004	92.1%	44,316	8,778	8,539	97.3%
Dec	31,859	9,095	8,190	90.0%	45,770	9,114	8,852	97.1%
Total	429,864	113,502	93,136	82.1%	479,612	107,678	99,948	92.8%

Figure 3-30 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: 2020 and 2021



PJM's process for solving and approving RT SCED cases, and selecting approved RT SCED cases to use in LPC to calculate LMPs had inconsistencies that lead to downstream impacts for energy and reserve dispatch and settlements. Until November 1, 2021, PJM did not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in 2020, while settlements are linked to five minute intervals. In 2021, the frequency of automatic execution of RT SCED cases was one every five minutes. Until November 1, 2021, RT SCED solved the dispatch problem for a target time that was generally 14 minutes in the future. An RT SCED case was approved and sent dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target did not match, and a new RT SCED case overrode the previously approved case before resources had time to achieve the previous target dispatch. Prior to October 15, 2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs for the present five minute interval. For example, the LPC case that calculated prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals for the target time of 10:10 EPT. This discrepancy created a mismatch between the MW dispatch and real-time LMPs and undermined generators' incentive to follow dispatch. Under new RT SCED changes that were implemented on October 15, 2020, PJM resolved the mismatch between LPC and the RT SCED target time, but prices no longer applied at the time when resources received and followed that dispatch signal.[64] For example, the LPC case that calculated prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals at 9:55 EPT which were no longer effective from 10:00 to 10:05 EPT. In the first 10 months of 2021, there was a mismatch between the MW dispatch and real-time LMPs that undermined generators' incentive to follow dispatch. The timing remained incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all corresponded to one another, which PJM implemented on November 1, 2021.

The extent to which dispatch instructions from approved SCED solutions are reflected in concurrent prices in the PJM Real-Time Energy Market can be measured by comparing the start and end times when the dispatch instructions from the RT SCED solution were effective with the start and end times when the corresponding prices applied. The start time for a dispatch instruction is the time at which PJM approves the RT SCED solution, which triggers sending the resulting dispatch instructions to resources. The end time for a dispatch instruction is the time when the next RT SCED solution is approved. Dispatch and pricing are perfectly aligned when the start and end times of the dispatch instructions from an approved RT SCED solution match with the start and end times of the LPC pricing interval that uses the same RT SCED solution. In a perfectly aligned five minute market, these times would both be five minutes in duration. In the first 10 months of 2021, RT SCED used a 10 minute ramp time to dispatch resources, while LPC applied prices to five minute intervals. Beginning November 1, 2021, both RT SCED and LPC used the same five minute period to dispatch resources and calculate prices, which aligned the dispatch signals and prices in the real-time energy market.

Table 3-40 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices in 2020 and 2021. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of

64 See Docket No. ER19-2573-000.

correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This was far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer corresponded to the dispatch instructions. Table 3-40 shows that during the first 10 months of 2021, the dispatch instructions were consistent with prevailing prices for only 33 seconds. During this period, the percent of time that prices were consistent with the dispatch instructions was 9.0 percent. This is because by the time LMPs reflected the dispatch signals from an approved RT SCED solution, dispatchers had approved a new solution, and resources were instructed to follow new dispatch signals that did not align with the LMPs used to settle the current five minute interval. In other words, prices consistently lagged dispatch instructions by five minutes, except in cases where dispatchers had not approved a new SCED solution five minutes after a previously approved solution. In the period beginning November 1, 2021, PJM aligned the dispatch and pricing intervals such that the prices that were effective for each five minute interval were generally based on the RT SCED case that sent dispatch signals with the target time at the end of the five minute interval. With these changes implemented on November 1, the dispatch instructions were consistent with the prices on average for 4 minutes and 46 seconds out of each five minute interval, or 95.4 percent of each five minute interval.

Table 3-40 Dispatch instructions reflected in prices: 2020 and 2021

Period	RT SCED Automatic Execution Frequency	Dispatch Duration Reflected in Prices (Minutes:Seconds)	Percent Dispatch Duration Reflected in Prices
Jan 1, 2020 - Feb 23, 2020	Every 3 minutes	03:11	67.9%
Feb 24, 2020 - Jun 22, 2020	Every 4 minutes	03:27	67.2%
Jun 23, 2020 - Oct 14, 2020	Every 5 minutes	03:37	69.9%
Oct 15, 2020 - Dec 31, 2020	Every 5 minutes	00:39	9.9%
Jan 1, 2021 - Oct 31, 2021	Every 5 minutes	00:33	9.0%
Nov 1, 2021 - Dec 31, 2021	Every 5 minutes	04:46	95.4%

For correct price signals and compensation, energy (LMP) and ancillary service pricing should align with the dispatch solution that is the basis for those prices and with the actual physical dispatch period during which that dispatch solution is realized for each and every real-time market interval.[65] This only happens when RT SCED and LPC both use a five minute ramp time, consistent with the five minute real-time settlement period in PJM. The MMU recommended that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. PJM adopted the recommended changes on November 1, 2021. This resulted in prices used to settle energy for the five minute interval that ends at the RT SCED dispatch target time calculated consistent with the economic dispatch that targets the end of that five minute interval.[66]

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 17:00 of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 17:00 of the second business day following the operating day.[67] Table 3-41 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2020 and 2021. In 2021, PJM recalculated LMPs for 1,502 five minute intervals or 1.43 percent of the total 105,120 five minute intervals. In February 2021, PJM recalculated LMPs for several five minute intervals due to a telemetry issue that affected the calculation of regulation performance scores.

65 See *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 (2016).
66 The implementation of fast start pricing on September 1, 2021, resulted in a much more significant misalignment between price and dispatch signals.
67 OA Schedule 1 § 1.10.8(e).

Table 3-41 Number of five minute interval real-time prices recalculated: January 2020 through December 2021

	2020		2021	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs were Recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs were Recalculated
January	8,928	193	8,928	12
February	8,352	12	8,064	496
March	8,916	110	8,916	49
April	8,640	50	8,640	266
May	8,928	37	8,928	29
June	8,640	64	8,640	22
July	8,928	67	8,928	190
August	8,928	251	8,928	58
September	8,640	20	8,640	31
October	8,928	37	8,928	22
November	8,652	22	8,652	162
December	8,928	80	8,928	165
Total	105,408	943	105,120	1,502

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[68]

PJM Day-Ahead Average LMP

Table 3-42 shows the day-ahead average LMP for 2001 through 2021. The day-ahead average LMP in 2021 increased 85.8 percent from 2020, from $20.33 per MWh to $37.76 per MWh.

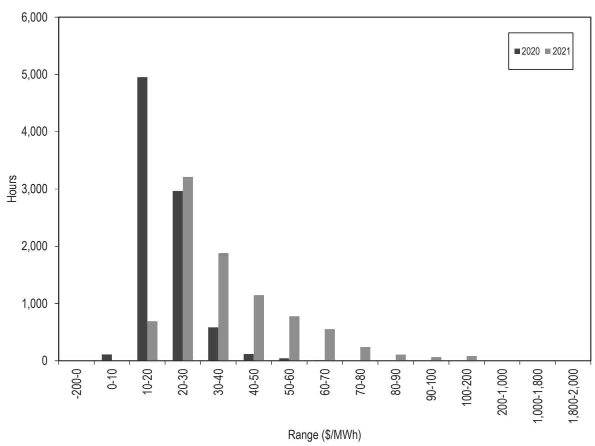
Table 3-42 Day-ahead average LMP (Dollars per MWh): 2001 through 2021

	Day-Ahead LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%
2014	$49.15	$38.10	$51.88	32.3%	10.0%	235.6%
2015	$34.12	$29.09	$22.59	(30.6%)	(23.7%)	(56.5%)
2016	$28.10	$25.76	$10.68	(17.7%)	(11.4%)	(52.7%)
2017	$29.48	$26.94	$11.69	4.9%	4.6%	9.5%
2018	$35.69	$30.96	$22.32	21.1%	14.9%	91.0%
2019	$26.03	$24.36	$9.35	(27.1%)	(21.3%)	(58.1%)
2020	$20.33	$18.99	$7.00	(21.9%)	(22.0%)	(25.2%)
2021	$37.76	$32.15	$18.49	85.8%	69.3%	164.3%

PJM Day-Ahead Average LMP Duration

Figure 3-31 shows the hourly distribution of the day-ahead average LMP in 2020 and 2021.

Figure 3-31 Distribution of day-ahead LMP: 2020 and 2021



Day-Ahead Load-Weighted Average LMP

Day-ahead load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead, hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up to congestion.

68 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of day-ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead Load-Weighted Average LMP

Table 3-43 shows the day-ahead load-weighted average LMP in 2001 through 2021. The day-ahead load-weighted average LMP in 2021 increased 84.0 percent from 2020, from $21.40 per MWh to $39.37 per MWh.

Table 3-43 Day-ahead load-weighted average LMP (Dollars per MWh): 2001 through 2021

	Day-Ahead Load-Weighted Average LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	37.8%	11.4%	230.4%
2015	$36.73	$30.60	$25.46	(31.5%)	(23.2%)	(57.3%)
2016	$29.68	$27.00	$11.64	(19.2%)	(11.8%)	(54.3%)
2017	$30.85	$28.21	$12.64	3.9%	4.5%	8.6%
2018	$37.97	$32.49	$24.76	23.1%	15.2%	95.9%
2019	$27.23	$25.28	$10.18	(28.3%)	(22.2%)	(58.9%)
2020	$21.40	$19.78	$7.59	(21.4%)	(21.7%)	(25.5%)
2021	$39.37	$33.72	$19.30	84.0%	70.5%	154.3%

PJM Day-Ahead Monthly Load-Weighted Average LMP

Figure 3-32 shows the day-ahead monthly and yearly load-weighted average LMP from 2001 through 2021.

Figure 3-32 Day-ahead monthly and yearly load-weighted average LMP: 2001 through 2021

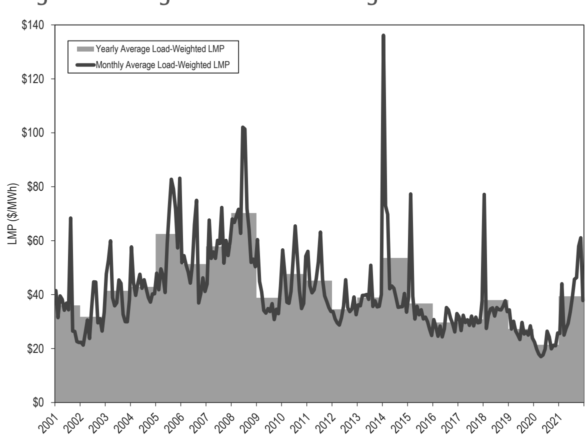
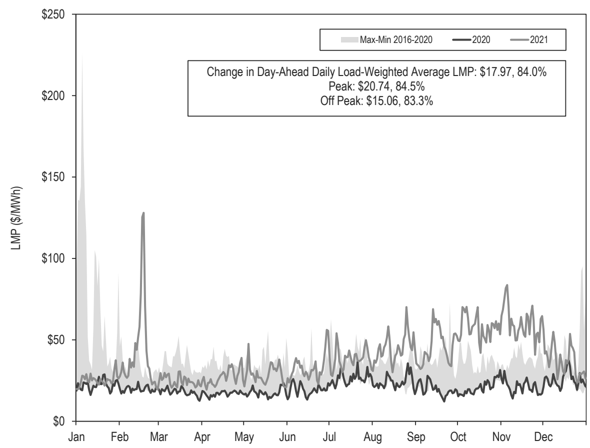


Figure 3-33 shows the day-ahead daily load-weighted average LMP in 2020 and 2021 compared to the historic five year price range.

Figure 3-33 Day-ahead daily load-weighted average LMP: 2020 and 2021



PJM Day-Ahead Monthly Inflation Adjusted Load-Weighted Average LMP

Figure 3-34 shows the PJM day-ahead, monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through December 2021.[69] Table 3-44 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for every year from 2000 through 2021. The PJM day-ahead inflation adjusted load-weighted average LMP in 2021 was the fifth lowest ($23.40 per MWh) since PJM day-ahead markets started in 2000. The day-ahead inflation adjusted monthly load-weighted average LMP for April 2020 ($10.70 per MWh) was the lowest monthly value since the day-ahead markets started.

69 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed January 12, 2022).

Figure 3-34 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through December 2021

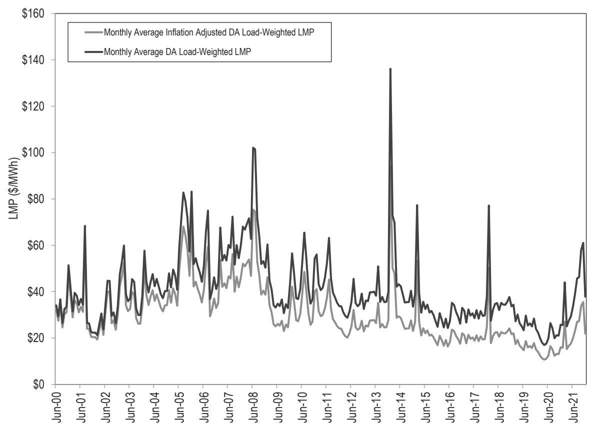


Table 3-44 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: 2000 through 2021

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
2000	$35.13	$32.74
2001	$36.01	$32.87
2002	$31.80	$28.53
2003	$41.43	$36.42
2004	$42.87	$36.65
2005	$62.50	$51.58
2006	$51.33	$41.12
2007	$57.88	$45.11
2008	$70.25	$52.61
2009	$38.82	$29.29
2010	$47.65	$35.32
2011	$45.19	$32.48
2012	$34.55	$24.33
2013	$38.93	$27.00
2014	$53.62	$36.71
2015	$36.73	$25.08
2016	$29.68	$19.98
2017	$30.85	$20.34
2018	$37.97	$24.47
2019	$27.23	$17.23
2020	$21.40	$13.35
2021	$39.37	$23.40

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the day-ahead and real-time energy markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome.

In practice, virtuals can receive a positive revenue anytime there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets. Virtual trading can only result in price convergence at a given location and market hour if the factors affecting prices at that location and hour, such as modeled contingencies, transmission constraint limits and sources of flows, are the same in both the day-ahead and real-time models.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to receive positive revenue from the activity for that reason regardless of the volume of those transactions and without improving the efficiency of the energy market. This is termed false arbitrage.

The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market. Price convergence does not necessarily mean a zero or even a very small difference in prices between day-ahead and real-time energy markets. There may be factors, from uplift charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences.

INCs, DECs and UTCs allow participants to benefit from price differences between the day-ahead and real-time energy market. In theory, virtual transactions receive positive revenues when they contribute to price convergence, but with false arbitrage, high revenues result with little or no price convergence. The seller of an INC must buy energy in the real-time energy market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC receives positive revenue. The buyer of a DEC must sell energy in the real-time energy market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC receives positive revenue.

The net revenue of a UTC transaction is the net of the separate revenues of the component INC and DEC. A UTC can have a net positive revenue if the positive revenue on one side of the UTC transaction exceeds the losses on the other side.

Virtual transactions, including UTCs since November 1, 2020, are required to pay uplift charges. Cleared INCs and DECs pay deviation charges based on the daily RTO and applicable regional operating reserve charge rates. DECs pay day-ahead operating reserve charges in addition to deviation charges. Cleared UTCs are treated, for uplift purposes, like DECs at the UTC sink point, and pay the regional and RTO deviation rates in addition to the day-ahead rate. Uplift charges for deviations may not apply if the virtual transaction is partially or fully offset by a corresponding real-time physical transaction at the same location.

Revenues of Virtual Transactions

Table 3-45 shows, before uplift charges, the number of cleared UTC transactions, the number of cleared UTCs with positive net revenues, the number of cleared UTCs with positive revenues at their source point and the number of cleared UTCs with positive revenues at their sink point in 2020 and 2021. In 2021, 49.8 percent of all cleared UTC transactions received positive net revenues before uplift charges. Of cleared UTC transactions, 66.4 percent received positive revenues on the source side and 34.7 percent received positive revenues on the sink side, but only 8.5 percent received positive revenues on both the source and sink side.

Table 3-45 Cleared UTC count with positive revenues by source and sink point before uplift charges: 2020 and 2021[70]

	Cleared UTCs	Positive Revenue UTCs	Positive Revenue at Source	Positive Revenue at Sink	Positive Revenue at Source and Sink	Share Positive Revenue Overall	Share Positive Revenue Source	Share Positive Revenue Sink	Share Positive Revenue Source and Sink
2020	8,967,923	3,258,573	4,117,742	2,401,044	458,392	36.3%	45.9%	26.8%	5.1%
2021	4,640,833	2,309,839	3,083,040	1,609,840	392,765	49.8%	66.4%	34.7%	8.5%

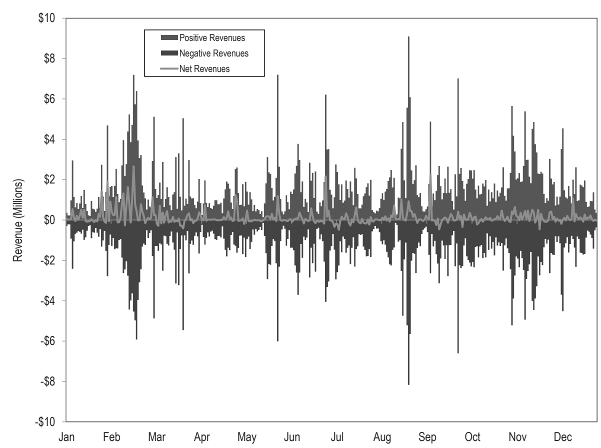
Table 3-46 shows the number of cleared INC and DEC transactions and the number of cleared transactions with positive revenues before uplift charges in 2020 and 2021. Of cleared INC and DEC transactions in 2021, 66.2 percent of INCs had positive revenues and 36.6 percent of DECs had positive revenues.

Table 3-46 Cleared INC and DEC count with positive revenues: 2020 and 2021

	Cleared INC	Positive Revenue INC	Positive Revenue INC Share	Cleared DEC	Positive Revenue DEC	Positive Revenue DEC Share
2020	2,256,236	1,095,857	48.6%	2,956,349	889,382	30.1%
2021	2,266,256	1,499,831	66.2%	2,238,301	818,266	36.6%

Figure 3-35 shows the total daily net revenues of UTCs with positive net revenues, with negative net revenues, and all UTCs, before uplift charges, in 2021.

Figure 3-35 UTC daily positive, negative, and net revenues before uplift charges: 2021[71]



70 Calculations exclude PJM administrative charges.

71 Calculations exclude PJM administrative charges.

Figure 3-36 shows the cumulative UTC daily total net revenues before operating reserve charges for each year from 2013 through 2021.

Figure 3-36 Cumulative daily UTC net revenues before uplift charges: January 2013 through December 2021

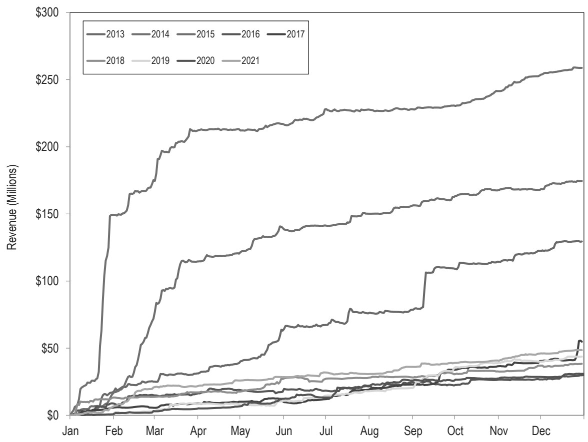


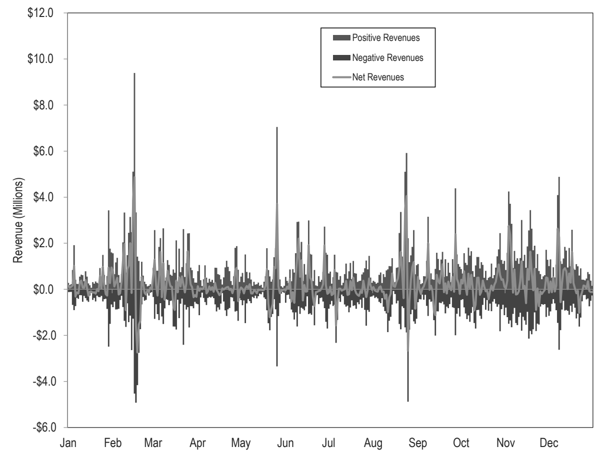
Table 3-47 shows UTC revenues before uplift charges by month for January 2013 through December 2021. May 2016, September 2016, February 2017, June 2018, September 2020, and July 2021 were the only months in this seven year period in which monthly net revenues were negative. Total UTC revenues before uplift charges were higher 2021 than in 2020 despite a significantly lower volume of bid and cleared UTC MWh in 2021.

Table 3-47 UTC net revenues before uplift charges by month: January 2013 through December 2021

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429	$8,573,276	$3,957,296	($141,240)	$1,628,186	$1,170,367	$2,319,727	$30,887,320
2021	$6,421,567	$13,241,294	$1,788,961	$4,529,921	$2,542,898	$3,384,291	($1,199,849)	$5,330,600	$2,649,331	$2,148,861	$5,091,590	$2,665,873	$48,595,339

Figure 3-37 shows total INC and DEC daily revenues before uplift charges, gross positive revenues, the sum of all positive revenue transactions, gross negative revenues, the sum of all negative revenue transactions, and net revenues in 2021.

Figure 3-37 INC and DEC daily positive, negative, and total revenues before uplift charges: 2021[72]



72 Calculations exclude PJM administrative charges.

Figure 3-38 shows total INC daily gross positive and negative revenues and net revenues before uplift charges in 2021.

Figure 3-38 INC daily positive, negative, and total net revenues before uplift charges 2021[73]

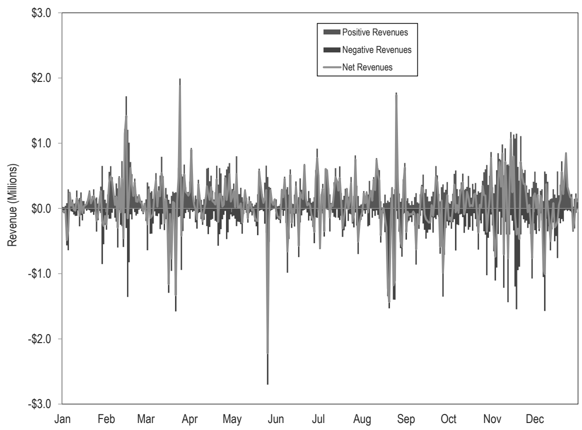


Figure 3-39 shows total DEC daily gross positive and negative revenues and net revenues before uplift charges in 2021.

Figure 3-39 DEC daily positive, negative, and total net revenues before uplift charges: 2021[74]

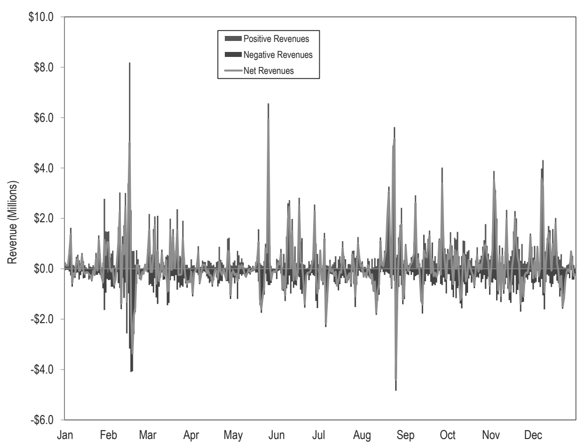
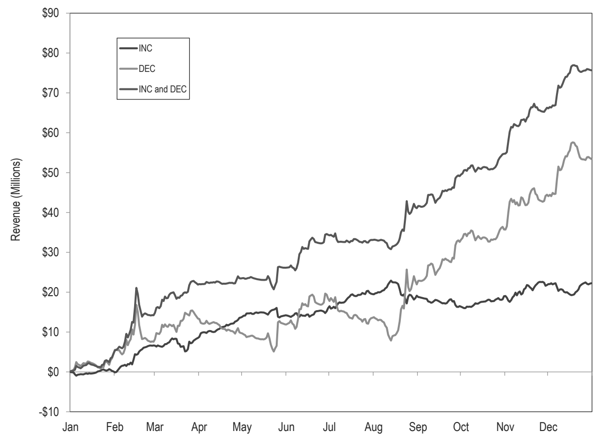


Figure 3-40 shows the cumulative INC and DEC daily revenues before uplift charges in 2021. The revenues of DECs increased after fast start pricing implementation on September 1, 2021.

Figure 3-40 Cumulative daily INC and DEC revenues before uplift charges: 2021



73 Calculations exclude PJM administrative charges.
74 Calculations exclude PJM administrative charges.

Table 3-48 shows INC and DEC revenues before uplift charges by month in 2021.

Table 3-48 INC and DEC revenues before uplift charges by month: 2021

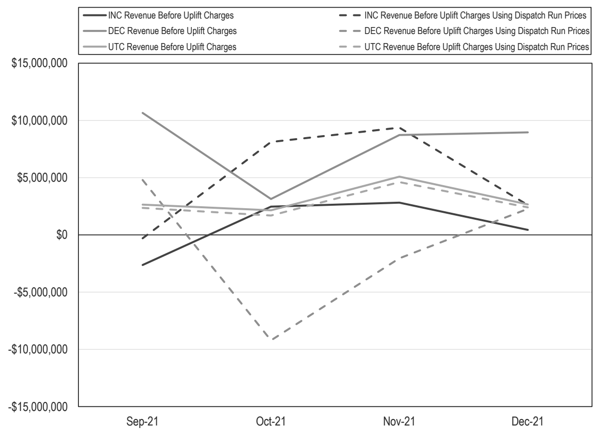
	January	February	March	April	May	June	July	August	September	October	November	December	Total
INCs	$116,313	$6,534,110	$1,874,664	$5,140,992	$554,421	$1,767,917	$3,526,962	($375,872)	($2,629,138)	$2,473,895	$2,818,830	$436,280	$22,239,372
DECs	$4,506,985	$3,060,102	$5,820,332	($3,623,933)	$2,168,601	$6,490,068	($4,855,699)	$8,379,135	$10,656,780	$3,136,842	$8,726,237	$8,963,319	$53,428,770
INCs and DECs	$4,623,297	$9,594,212	$7,694,996	$1,517,059	$2,723,022	$8,257,985	($1,328,736)	$8,003,263	$8,027,641	$5,610,737	$11,545,067	$9,399,600	$75,668,143

Effect of Fast Start Pricing on Virtuals

The implementation of fast start pricing on September 1, 2021, has resulted in changes to the settlement of virtual transactions. Prior to fast start pricing, virtual products were cleared and settled based on a single set of prices. The dispatch and pricing run prices were the same. With fast start pricing, all virtual products are cleared using day-ahead dispatch run prices, but pay and receive the day-ahead and real-time pricing run prices. The use of fast start pricing has a direct impact on virtual settlements through the use of prices different from those used to dispatch virtuals. This means that a DEC may clear in the day-ahead market, based on the dispatch run, even though its offer is lower than the final, pricing run price. Likewise, an INC may clear even though its offer is higher than the day-ahead market price. The use of fast start pricing also results in divergences between day-ahead and real-time prices, which can be targeted by virtual traders. Because fast start pricing is more frequent in the real-time market, it means that, all else equal, real-time prices are higher than they otherwise would be, increasing the profitability of DECs and decreasing the profitability of INCs.

Figure 3-41 shows the total monthly revenues before uplift charges received by INCs, DECs, and UTCs, compared to the revenues they would have received if dispatch run prices had been used in settlement. In 2021, the use of fast start pricing significantly increased revenues for DECs, significantly decreased revenues for INCs, and increased revenues for UTCs, although not significantly.

Figure 3-41 Total monthly actual revenues before uplift charges versus hypothetical revenues calculated using dispatch run prices for INCs, DECs, and UTCs: September 1, 2021 through December 31, 2021



There are incentives to use virtual transactions to profit from price differences between the day-ahead and real-time energy markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets, about modeling differences and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the day-ahead energy market. Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis.

Day-ahead and Real-time Prices

Table 3-49 shows the difference between the day-ahead and the real-time average LMP.

Table 3-49 Day-ahead and real-time average LMP (Dollars per MWh): 2020 and 2021[75]

	2020				2021			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$20.33	$20.66	$0.33	1.6%	$37.76	$38.18	$0.42	1.1%
Median	$18.99	$18.35	($0.64)	(3.5%)	$32.15	$30.59	($1.57)	(5.1%)
Standard deviation	$7.00	$11.77	$4.78	40.6%	$18.49	$26.37	$7.88	29.9%
Peak average	$23.67	$24.09	$0.42	1.7%	$44.06	$44.54	$0.47	1.1%
Peak median	$21.64	$20.52	($1.12)	(5.5%)	$38.16	$36.19	($1.97)	(5.4%)
Peak standard deviation	$7.24	$13.99	$6.74	48.2%	$20.61	$31.44	$10.83	34.5%
Off peak average	$17.39	$17.64	$0.25	1.4%	$32.23	$32.60	$0.37	1.1%
Off peak median	$16.54	$16.29	($0.25)	(1.5%)	$27.40	$26.82	($0.58)	(2.2%)
Off peak standard deviation	$5.23	$8.30	$3.08	37.0%	$14.28	$19.27	$4.99	25.9%

The price difference between the real-time and the day-ahead energy markets results in part, from conditions in the real-time energy market that are difficult, or impossible, to anticipate in the day-ahead energy market.

Table 3-50 shows the difference between the day-ahead and the real-time load-weighted LMP for 2001 through 2021.

Table 3-50 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): 2001 through 2021

	Load-Weighted Average LMP			
	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)
2014	$49.15	$48.22	($0.93)	(1.9%)
2015	$34.12	$33.39	($0.73)	(2.1%)
2016	$28.10	$27.57	($0.53)	(1.9%)
2017	$29.48	$29.42	($0.06)	(0.2%)
2018	$35.69	$35.75	$0.06	0.2%
2019	$26.03	$26.02	($0.01)	(0.1%)
2020	$20.33	$20.66	$0.33	1.6%
2021	$37.76	$38.18	$0.42	1.1%

75 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-51 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP in 2020 and 2021.

Table 3-51 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): 2020 and 2021

	2020		2021	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	0	0.00%	0	0.00%
($200) to ($100)	0	0.00%	0	0.00%
($100) to ($50)	0	0.14%	12	0.00%
($50) to $0	5,522	64.57%	5,644	62.86%
$0 to $50	3,221	98.38%	2,962	99.53%
$50 to $100	35	99.54%	102	99.93%
$100 to $200	4	99.87%	29	99.98%
$200 to $400	2	99.99%	10	100.00%
$400 to $800	0	100.00%	1	100.00%
>= $800	0	100.00%	0	100.00%

Figure 3-42 shows the differences between day-ahead and real-time hourly average LMP in 2021. The average difference was $1.63 per MWh for September through December after fast start pricing was implemented, an increase of $1.85 per MWh from -$0.22 per MWh for January through August.

Figure 3-42 Real-time hourly average LMP minus day-ahead hourly average LMP: 2021

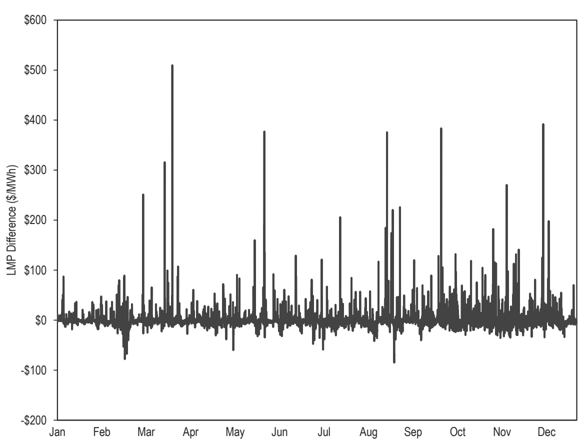
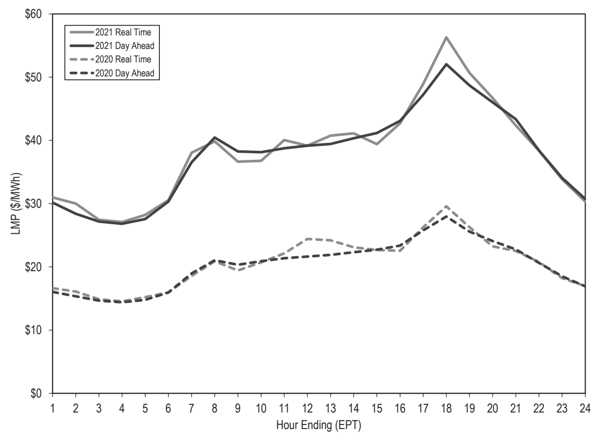


Figure 3-43 shows day-ahead and real-time load-weighted average LMP by hour of the day in 2020 and 2021.

Figure 3-43 System hourly average LMP: 2020 and 2021



Zonal LMP and Dispatch

Table 3-52 shows real-time zonal average and load-weighted average LMP in 2020 and 2021.

Table 3-52 Real-time zonal average and load-weighted average LMP (Dollars per MWh): 2020 and 2021

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
Zone	2020	2021	Percent Change	2020	2021	Percent Change
ACEC	$18.44	$31.97	73.4%	$19.72	$34.13	73.1%
AEP	$21.17	$38.94	83.9%	$22.14	$40.31	82.1%
APS	$21.29	$39.05	83.5%	$22.40	$40.44	80.5%
ATSI	$21.34	$37.99	78.0%	$22.55	$39.47	75.1%
BGE	$23.98	$43.63	81.9%	$25.78	$45.77	77.6%
COMED	$19.04	$35.02	83.9%	$20.18	$37.00	83.3%
DAY	$22.08	$40.98	85.6%	$23.23	$42.92	84.7%
DUKE	$21.33	$39.68	86.1%	$22.37	$41.49	85.5%
DOM	$21.85	$42.69	95.4%	$23.05	$44.67	93.8%
DPL	$20.68	$37.84	83.0%	$22.90	$40.24	75.8%
DUQ	$21.37	$37.66	76.2%	$22.79	$39.17	71.9%
EKPC	$21.07	$39.25	86.3%	$22.14	$41.20	86.1%
JCPLC	$18.63	$32.55	74.7%	$20.05	$34.52	72.2%
MEC	$19.78	$37.86	91.4%	$21.16	$39.97	88.9%
OVEC	$20.64	$38.02	84.2%	$20.75	$37.98	83.0%
PECO	$18.25	$31.93	75.0%	$19.29	$33.55	73.9%
PE	$19.94	$36.50	83.1%	$20.84	$37.73	81.1%
PEPCO	$22.23	$42.48	91.1%	$23.59	$44.62	89.2%
PPL	$18.44	$34.58	87.6%	$19.42	$35.92	85.0%
PSEG	$18.73	$34.09	82.0%	$19.69	$35.78	81.7%
REC	$19.38	$36.46	88.1%	$20.74	$38.80	87.1%
PJM	$20.66	$38.18	84.8%	$21.77	$39.78	82.8%

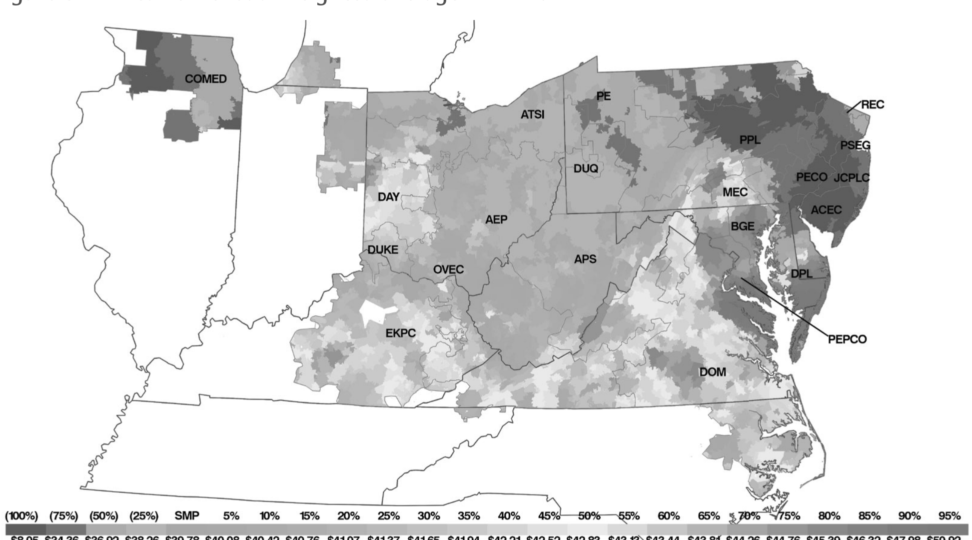
Table 3-53 shows day-ahead zonal average and load-weighted average LMP in 2020 and 2021.

Table 3-53 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): 2020 and 2021

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
Zone	2020	2021	Percent Change	2020	2021	Percent Change
ACEC	$18.01	$31.89	77.0%	$19.18	$33.90	76.7%
AEP	$20.92	$38.49	84.0%	$21.89	$39.93	82.4%
APS	$20.91	$38.73	85.2%	$21.96	$40.05	82.4%
ATSI	$20.92	$38.25	82.8%	$21.91	$39.56	80.6%
BGE	$23.74	$43.36	82.6%	$25.36	$45.51	79.5%
COMED	$18.97	$34.76	83.3%	$20.01	$36.49	82.4%
DAY	$22.00	$40.73	85.1%	$23.19	$42.69	84.1%
DUKE	$21.35	$39.73	86.0%	$22.50	$41.42	84.1%
DOM	$21.66	$41.55	91.9%	$22.89	$43.66	90.8%
DPL	$19.55	$36.71	87.7%	$21.47	$39.43	83.7%
DUQ	$21.00	$37.73	79.7%	$22.27	$39.21	76.1%
EKPC	$20.84	$38.74	85.9%	$22.17	$40.90	84.5%
JCPLC	$18.07	$32.69	80.9%	$19.23	$34.52	79.4%
MEC	$19.00	$37.60	97.9%	$20.23	$39.66	96.0%
OVEC	$20.45	$37.77	84.7%	$21.12	$40.95	93.9%
PECO	$17.78	$31.79	78.8%	$18.75	$33.24	77.3%
PE	$19.90	$37.12	86.5%	$21.13	$38.93	84.3%
PEPCO	$22.12	$41.80	89.0%	$23.55	$44.05	87.1%
PPL	$17.92	$34.51	92.6%	$18.82	$35.73	89.8%
PSEG	$18.24	$33.31	82.6%	$19.18	$34.91	82.1%
REC	$18.74	$35.40	88.9%	$20.22	$38.00	87.9%
PJM	$20.33	$37.76	85.8%	$21.40	$39.37	84.0%

Figure 3-44 is a map of the real-time load-weighted average LMP in 2021. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP.

Figure 3-44 Real-time load-weighted average LMP: 2021



Transmission Penalty Factors

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Table 3-54 shows the frequency and average shadow price of transmission constraints in PJM. In 2021, there were 170,067 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly eight percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.[76] In 2021, the average shadow price of transmission constraints when the line limit was violated was nearly 8.8 times higher than when the transmission constraint was binding at its limit.

76 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

Table 3-54 Frequency and average shadow price of transmission constraints: 2020 and 2021

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2020	2021	2020	2021
PJM Internal Violated Transmission Constraints	7,374	13,782	$1,549.04	$1,599.42
PJM Internal Binding Transmission Constraints	117,867	102,529	$92.23	$183.04
Market to Market Transmission Constraints	40,722	53,756	$219.15	$459.12
All Transmission Constraints	165,963	170,067	$188.10	$385.09

Table 3-55 shows the frequency of PJM internal violated transmission constraints by voltage level. In 2021, 92.6 percent of the PJM internal violated transmission constraint intervals had a voltage level at or above 230 kV.

Table 3-55 Frequency of PJM internal violated transmission constraints by voltage: 2020 and 2021

	2020		2021	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
69 kV	443	6.0%	2,001	14.5%
115 kV	2,546	34.5%	2,864	20.8%
138 kV	2,573	34.9%	4,591	33.3%
161 kV	24	0.3%	33	0.2%
230 kV	1,135	15.4%	3,268	23.7%
345 kV	133	1.8%	452	3.3%
500 kV	520	7.1%	539	3.9%
765 kV	-	0.0%	34	0.2%
Total	7,374	100.0%	13,782	100.0%

Transmission penalty factors should be applied without discretion, but not without additional rules that prevent unintended consequences. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. But the potential for prolonged and excessively high administrative pricing in the energy market due to transmission constraint penalty factors remains an issue that needs to addressed. There can be situations in which the application of transmission penalty factors in real time for significant periods creates manipulation opportunities for virtuals and creates inefficient wealth transfers when market participants do not have the ability to react to the high prices either on the supply or demand side.[77] This could be the result of a lengthy planned transmission outage, for example.[78] PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020.

PJM continues the practice of discretionary reductions in line limits. Table 3-56 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In 2021, there were 13,319 or 97 percent of 13,782 internal violated transmission constraint intervals in the real-time market with constraint limit less than 100 percent of the actual constraint limit. In 2021, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 6.8 percent.

Table 3-56 Frequency of reduction in line ratings (constraint intervals): 2020 and 2021

	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
Description	2020	2021	2020	2021	2020	2021
PJM Internal Violated Transmission Constraints	7,374	13,782	6,779	13,319	6.8%	12.1%
PJM Internal Binding Transmission Constraints	117,867	102,529	115,866	101,378	8.9%	7.3%
Market to Market Transmission Constraints	40,722	53,756	9,841	18,180	5.9%	6.5%
All Transmission Constraints	165,963	170,067	132,486	132,877	8.5%	7.7%

77 See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).
78 See *id.*

Table 3-57 shows the impact on LMP of PJM dispatchers reducing the line ratings of transmission constraints and causing artificial line limit violations. The transmission penalty factor's contribution to the load weighted average LMP of all violated transmission constraints in 2021 was $3.31 per MWh. If the actual lines limits were used for the internal PJM transmission constraints and everything remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load weighted average LMP would have decreased to $0.74 per MWh or 77.7 percent lower.

Table 3-57 Real-time LMP impact of reduced line limits for PJM transmission constraints (Dollars per MWh): 2020 and 2021

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2020	2021
Line Limits Reduced by PJM (Actual)	$1.67	$3.31
Hypothetical Use of Full Line Limits	$0.53	$0.74
Change in LMP	($1.14)	($2.57)
Percent Change in LMP	(68.5%)	(77.7%)

Table 3-58 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In 2021, there were 10,040 or 73 percent of internal violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

Table 3-58 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): 2020 and 2021

	2020			2021		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
PJM Violated Transmission Constraints	5,031	88	2,255	10,040	190	3,552
PJM Binding Transmission Constraints	109,731	155	7,981	100,359	26	2,144
Market to Market Transmission Constraints	2,956	-	37,766	11,707	-	42,049
All Transmission Constraints	117,718	243	48,002	122,106	216	47,745

Transmission constraint penalty factors frequently set prices when PJM models a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the $2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

PJM used CT pricing logic until the implementation of fast start pricing on September 1, 2021, to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM committed a resource that is uneconomic and/or offered with inflexible parameters, PJM used CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.[79] Frequently, PJM dispatchers also manually overrode the transmission violation penalty factor of the constraint to match the offer price of the resource to artificially control the shadow price of the constraint. Table 3-59 shows the frequency of CT pricing logic used in the PJM Real-Time Energy Market. In 2021, there were 9,073 constraint intervals in the real-time market where CT pricing logic was used. In the PJM CT pricing logic, there could be one or multiple resources paired with a constraint.

PJM's use of CT pricing logic was inconsistent with the efficient market dispatch and pricing. For that reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.[80]

79 PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.
80 167 FERC ¶ 61,058 at P 69 (2019).

Table 3-59 Frequency of CT pricing logic used in the real-time market (constraint intervals): January 2020 through December 2021

Month	2020	2021
Jan	231	783
Feb	167	469
Mar	122	1,186
Apr	173	1,539
May	632	1,204
Jun	825	1,240
Jul	842	1,102
Aug	1,189	1,550
Sep	1,982	-
Oct	2,017	-
Nov	956	-
Dec	1,404	-
Total	10,540	9,073

Net Generation by Zone

Figure 3-45 shows the difference between the PJM real-time generation and real-time load by zone in 2021. Figure 3-45 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. Table 3-60 shows the difference between the real-time generation and real-time load by zone in 2020 and 2021.

Figure 3-45 Map of real-time generation less real-time load by zone: 2021[81]

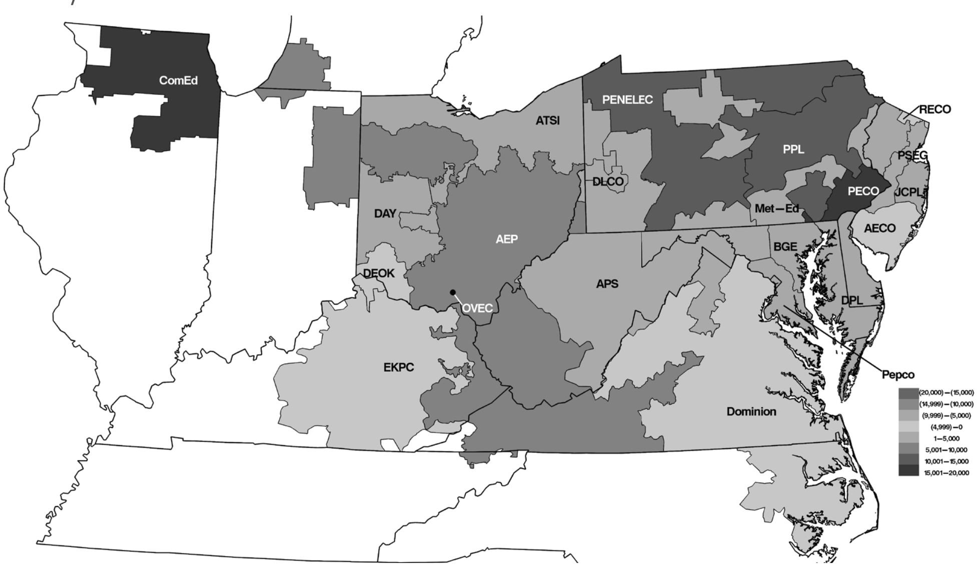


Table 3-60 Real-time generation less real-time load by zone (GWh): 2020 and 2021

Zonal Generation and Load (GWh)						
	2020			2021		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	3,489.7	9,489.2	(5,999.5)	2,847.6	9,871.0	(7,023.4)
AEP	135,989.6	120,710.5	15,279.1	140,957.6	124,326.2	16,631.5
APS	49,068.0	46,870.7	2,197.3	54,981.2	48,015.3	6,965.9
ATSI	46,182.2	62,400.1	(16,217.9)	50,703.3	64,510.0	(13,806.7)
BGE	16,588.2	29,631.1	(13,042.9)	18,196.5	30,462.3	(12,265.8)
COMED	128,261.3	90,687.4	37,573.9	131,324.5	92,872.9	38,451.6
DAY	1,055.1	16,426.9	(15,371.8)	1,159.5	16,862.6	(15,703.0)
DUKE	18,686.7	25,464.3	(6,777.6)	17,874.3	26,091.1	(8,216.8)
DOM	105,435.8	98,774.8	6,661.0	97,159.3	106,128.1	(8,968.9)
DPL	5,163.8	17,724.5	(12,560.6)	4,437.8	18,342.3	(13,904.5)
DUQ	16,052.6	12,818.6	3,234.0	15,973.6	13,018.1	2,955.5
EKPC	8,177.8	12,407.8	(4,230.0)	10,092.3	12,763.1	(2,670.8)
JCPLC	8,492.6	21,515.4	(13,022.7)	7,771.4	22,015.9	(14,244.5)
MEC	19,838.6	14,999.2	4,839.4	18,892.4	15,413.5	3,478.9
OVEC	9,033.1	111.9	8,921.1	10,063.7	114.5	9,949.2
PECO	73,151.5	37,413.7	35,737.8	73,258.1	38,435.5	34,822.6
PE	38,245.1	16,424.3	21,820.8	41,005.3	16,657.1	24,348.3
PEPCO	11,342.9	27,059.6	(15,716.7)	12,176.4	27,771.2	(15,594.8)
PPL	62,309.6	39,286.2	23,023.4	68,075.4	40,205.4	27,870.0
PSEG	42,237.0	41,385.2	851.8	43,374.6	42,137.7	1,237.0
RECO	0.0	1,385.8	(1,385.8)	0.0	1,411.4	(1,411.4)

81 Real-time zonal generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during intervals when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during intervals when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-61 shows PJM generation by fuel source in GWh in 2020 and 2021. In 2021, generation from coal units increased 17.8 percent, generation from natural gas units decreased 2.3 percent, and generation from oil increased 11.5 percent compared to 2020. Wind and solar output rose by 15.7 percent compared to 2020, supplying 4.2 percent of PJM energy in 2021.

Table 3-61 Generation (By fuel source (GWh)): 2020 and 2021[82] [83]

	2020		2021		Change in
	GWh	Percent	GWh	Percent	Output
Coal	156,575.0	19.3%	184,412.3	22.2%	17.8%
Bituminous	143,556.3	17.7%	163,753.6	19.7%	14.1%
Sub Bituminous	7,726.0	1.0%	14,421.7	1.7%	86.7%
Other Coal	5,292.7	0.7%	6,237.0	0.7%	17.8%
Nuclear	276,607.6	34.2%	272,670.4	32.8%	(1.4%)
Gas	322,505.4	39.8%	314,885.1	37.9%	(2.4%)
Natural Gas CC	294,712.8	36.4%	289,136.6	34.8%	(1.9%)
Natural Gas CT	18,849.2	2.3%	19,894.4	2.4%	5.5%
Natural Gas Other Units	6,995.6	0.9%	4,132.1	0.5%	(40.9%)
Other Gas	1,947.8	0.2%	1,722.0	0.2%	(11.6%)
Hydroelectric	16,423.3	2.0%	16,624.8	2.0%	1.2%
Pumped Storage	4,950.4	0.6%	5,037.3	0.6%	1.8%
Run of River	10,036.7	1.2%	10,278.6	1.2%	2.4%
Other Hydro	1,436.2	0.2%	1,308.9	0.2%	(8.9%)
Wind	26,433.2	3.3%	27,651.4	3.3%	4.6%
Waste	4,423.1	0.5%	4,475.9	0.5%	1.2%
Oil	2,054.8	0.3%	2,290.7	0.3%	11.5%
Heavy Oil	86.0	0.0%	65.6	0.0%	(23.7%)
Light Oil	282.2	0.0%	524.4	0.1%	85.8%
Diesel	30.1	0.0%	27.7	0.0%	(8.0%)
Other Oil	1,656.4	0.2%	1,673.1	0.2%	1.0%
Solar	3,869.5	0.5%	7,412.2	0.9%	91.6%
Battery	36.1	0.0%	36.5	0.0%	1.0%
Biofuel	914.3	0.1%	1,191.7	0.1%	30.3%
Total	809,842.4	100.0%	831,650.8	100.0%	2.7%

82 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, power to run pumped hydro pumps or power to charge batteries.

83 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-62 Monthly generation (By fuel source (GWh)): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	17,819.0	21,469.5	13,310.1	11,172.7	12,362.1	18,648.7	22,063.1	21,631.5	14,109.9	9,779.1	9,750.0	12,296.5	184,412.3
Bituminous	16,369.6	18,774.2	12,427.5	10,305.2	10,666.7	16,171.8	19,254.9	18,965.2	12,600.2	8,749.6	8,633.5	10,835.2	163,753.6
Sub Bituminous	901.4	2,124.5	312.7	610.2	1,239.6	1,973.5	2,210.7	2,084.5	1,033.1	551.0	596.3	784.2	14,421.7
Other Coal	548.0	570.7	570.0	257.3	455.9	503.4	597.4	581.9	476.6	478.5	520.1	677.2	6,237.0
Nuclear	25,133.4	22,125.3	21,217.1	19,692.2	21,841.2	23,374.4	23,641.8	24,278.8	22,860.1	21,553.9	22,064.7	24,887.6	272,670.4
Gas	26,011.3	22,670.8	23,925.8	21,904.3	22,545.8	27,745.0	31,466.8	33,188.4	25,813.1	26,429.6	25,908.7	27,275.5	314,885.1
Natural Gas CC	25,125.8	21,754.8	23,076.4	20,077.2	20,964.3	24,758.6	27,853.9	28,767.1	23,798.7	23,872.8	23,003.8	26,083.1	289,136.6
Natural Gas CT	616.1	579.9	569.5	1,465.1	1,131.2	2,333.8	2,881.6	3,703.3	1,439.1	2,164.9	2,232.1	777.8	19,894.4
Natural Gas Other Units	108.9	198.0	120.1	221.1	296.3	511.5	590.7	573.1	437.6	259.1	539.0	276.7	4,132.1
Other Gas	160.6	138.1	159.8	140.8	154.0	141.0	140.6	145.0	137.6	132.8	133.8	137.9	1,722.0
Hydroelectric	1,481.8	1,299.8	1,682.6	1,317.5	1,295.9	1,313.5	1,594.6	1,509.5	1,574.4	1,264.0	1,224.4	1,066.8	16,624.8
Pumped Storage	398.4	354.0	311.9	244.7	357.1	539.8	637.4	665.8	544.6	376.0	253.0	354.7	5,037.3
Run of River	994.9	847.5	1,282.8	1,004.4	865.0	618.6	775.5	669.0	899.3	785.1	913.5	623.0	10,278.6
Other Hydro	88.5	98.3	87.9	68.4	73.8	155.1	181.7	174.7	130.5	102.9	58.0	89.1	1,308.9
Wind	2,486.7	2,595.4	3,399.1	2,684.5	2,110.4	1,691.5	1,073.3	1,087.1	2,137.8	2,190.1	2,987.2	3,208.4	27,651.4
Waste	386.1	316.6	391.6	369.1	389.6	388.0	386.4	374.8	333.5	379.3	368.9	391.8	4,475.9
Oil	159.7	254.1	151.5	166.4	205.6	200.0	199.8	277.0	161.2	159.7	174.8	181.1	2,290.7
Heavy Oil	0.0	0.0	0.3	0.0	0.0	0.0	15.9	41.0	4.4	0.1	1.9	1.9	65.6
Light Oil	7.0	136.5	23.2	12.2	51.2	89.9	44.5	92.9	5.4	8.0	32.1	21.6	524.4
Diesel	1.4	2.8	1.2	3.6	0.2	4.0	5.4	5.0	0.9	0.3	0.5	2.3	27.7
Other Oil	151.4	114.8	126.8	150.6	154.1	106.1	134.0	138.0	150.5	151.4	140.2	155.3	1,673.1
Solar	303.6	279.3	578.7	711.4	814.7	809.6	874.3	789.8	752.0	558.5	549.5	390.7	7,412.2
Battery	2.7	3.3	3.2	4.0	3.7	3.0	3.3	2.7	2.6	2.7	2.3	3.0	36.5
Biofuel	97.4	81.4	63.7	72.1	131.6	119.6	129.2	123.1	109.5	39.2	95.4	129.6	1,191.7
Total	73,881.8	71,095.4	64,723.4	58,094.1	61,700.6	74,293.3	81,432.5	83,262.7	67,853.9	62,356.1	63,125.9	69,831.0	831,650.8

Table 3-63 shows generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008.

Table 3-63 Share of generation by fuel source: 2008 through 2021

	Natural Gas	Coal	Nuclear	Other Fuel Type
2008	7.4%	54.9%	34.7%	3.0%
2009	10.0%	50.3%	35.9%	3.7%
2010	11.7%	49.3%	34.6%	4.4%
2011	14.1%	47.1%	34.5%	4.3%
2012	18.8%	42.1%	34.6%	4.5%
2013	16.7%	44.2%	34.8%	4.3%
2014	17.8%	43.3%	34.4%	4.5%
2015	23.0%	36.2%	35.5%	5.3%
2016	26.5%	33.9%	34.4%	5.3%
2017	26.8%	31.8%	35.6%	5.9%
2018	30.6%	28.6%	34.2%	6.6%
2019	36.2%	23.8%	33.6%	6.4%
2020	39.6%	19.3%	34.2%	6.9%
2021	37.7%	22.2%	32.8%	7.4%

Fuel Diversity

Figure 3-46 shows the fuel diversity index (FDI_e) for PJM energy generation.[84] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-62 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from

84 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

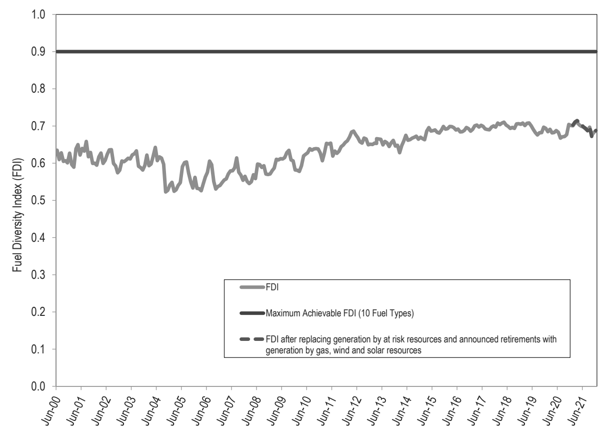
51.3 percent prior to 2012 to 31.8 percent from 2012 through September 30, 2021. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light Control Zones and the increased shares of coal and nuclear that resulted.[85] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 54.9 percent in 2008 and 22.2 percent in 2021. Gas generation as a share of total generation was 7.4 percent in 2008 and 37.9 percent in 2021. Wind generation as a share of total generation was 0.5 percent in 2008 and 3.3 percent in 2021.

The FDI_e increased 1.8 percent in 2021 compared to 2020. The increase in FDI_e is primarily due to an increase in coal generation in 2021 compared to 2020.

The FDI_e was also used to measure the impact on fuel diversity of potential retirements. A total of 2,230 MW of capacity were identified as being at risk of retirement.[86] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[87] There are 7,081.0 MW of generation that have requested retirement after December 31, 2021.[88] The at risk units and other generators with deactivation notices generated 13,267.4 GWh in 2021. The dashed line in Figure 3-46 shows a counterfactual result for FDI_e assuming the 13,267.4 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas, wind and solar generation.[89] The FDI_e for 2021 under the counterfactual assumption would have been 0.2 percent lower than the actual FDI_e.

85 See the *2019 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Control Zones occurred in October 2004.
86 See Table 7-47 in the *2021 State of the Market Report for PJM*, Volume II, Section 7: Net Revenue.
87 See PJM. OATT: § V "Generation Deactivation."
88 See Table 12-11 in the *2021 State of the Market Report for PJM*, Section 12: Generation and Transmission Planning.
89 It is assumed that 7,669.5 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2021 levels in renewable generation through December 31, 2021 that is required by RPS in 2022. The split between solar and wind, 5,580.6 GWh solar and 2,088.9 GWh wind, is based on queue data.

Figure 3-46 Fuel diversity index for monthly generation: June 2000 through December 2021



Natural Gas Supply Issues

A combination of pipeline transportation and natural gas supplies is needed to deliver natural gas to power plants. A generator could purchase a delivered service in which the seller bundles both the transportation and fuel to make deliveries to the plant. The delivered service could be purchased on either a term contract or a spot basis. A generator could secure pipeline transportation for part or all of the supplies needed to run the plant and purchase commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Other options are also possible.

The increase in natural gas fired capacity in PJM has highlighted issues with the dependence of the PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, creates risks for the bulk power system. PJM should collect data on each individual generator's fuel supply arrangements, and analyze the associated locational and regional risks to reliability.

In 2020 and 2021, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. These notices may, depending on the nature of the transportation service purchased, permit the pipelines to restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. The independent operations of geographically overlapping pipelines during extreme conditions highlights the potential shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of supply and demand. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrates the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.

Types of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the day-ahead energy market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market that can set price via their offers and bids.

Table 3-64 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In 2021, coal units were 14.1 percent and natural gas units were 71.7 percent of marginal resources. In 2021, natural gas combined cycle units were 59.7 percent of marginal resources. In 2020, coal units were 17.5 percent and natural gas units were 72.6 percent of the total marginal resources. In 2020, natural gas combined cycle units were 64.3 percent of the total marginal resources. In 2021, 77.8 percent of the wind marginal units had negative offer prices, 20.9 percent had zero offer prices and 1.4 percent of the wind marginal units had positive offer prices. In 2020, 92.8 percent of the wind marginal units had negative offer prices, 7.2 percent had zero offer prices and none had positive offer prices.

The proportion of marginal nuclear units decreased from 1.35 percent in 2020 to 1.00 percent in 2021. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

PJM implemented fast start pricing on September 1, 2021. Starting with September 1, 2021, the marginal resources shown in Table 3-64 are from the pricing run, which may not be same as marginal resources from the dispatch run.

Table 3-64 Type of fuel used and technology (By real-time marginal units): 2017 through 2021[90]

Fuel	Technology	2017	2018	2019	2020	2021
Gas	CC	44.63%	53.45%	62.13%	64.33%	59.75%
Coal	Steam	32.28%	27.26%	24.37%	17.53%	14.15%
Wind	Wind	7.28%	2.56%	3.81%	6.75%	11.04%
Gas	CT	4.70%	7.80%	5.97%	5.89%	10.06%
Gas	Steam	3.52%	1.68%	1.29%	2.12%	1.17%
Oil	CT	5.18%	4.58%	0.49%	1.25%	1.13%
Uranium	Steam	1.23%	1.04%	1.31%	1.35%	1.00%
Other	Solar	0.18%	0.12%	0.07%	0.33%	0.76%
Gas	RICE	0.40%	0.41%	0.00%	0.29%	0.67%
Other	Steam	0.19%	0.15%	0.06%	0.03%	0.08%
Oil	Steam	0.05%	0.29%	0.03%	0.06%	0.06%
Oil	RICE	0.26%	0.42%	0.00%	0.04%	0.06%
Oil	CC	0.01%	0.13%	0.01%	0.00%	0.02%
Municipal Waste	Steam	0.01%	0.04%	0.02%	0.02%	0.02%
Landfill Gas	CT	0.00%	0.00%	0.01%	0.01%	0.01%
Municipal Waste	RICE	0.00%	0.04%	0.00%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.02%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.04%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	RICE	0.02%	0.00%	0.00%	0.00%	0.00%

90 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Figure 3-47 shows the type of fuel used by marginal resources in the real-time energy market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-47 Type of fuel used (By real-time marginal units): 2004 through 2021

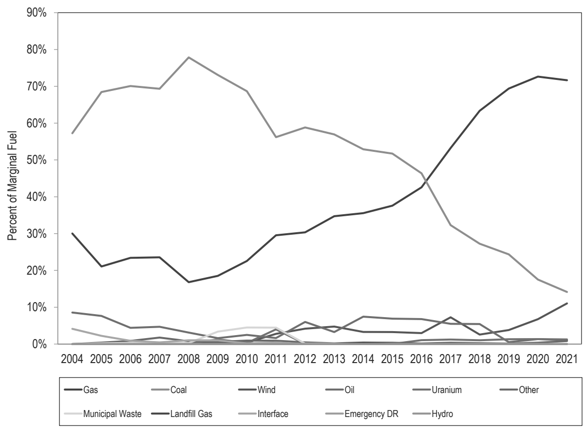


Table 3-65 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market since the implementation of fast starting pricing in September 2021. In the first four months of the fast start pricing implementation, marginal fast start resources accounted for 9.72 percent of all marginal resources in the pricing run.

Table 3-65 Fuel type and technology (Real-time marginal units and fast start marginal units): September through December, 2021

		2021 (Sep - Dec)		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	7.65%	7.65%
Gas	CC	0.00%	59.82%	59.82%
Gas	CT	7.55%	5.40%	12.95%
Gas	RICE	1.07%	0.05%	1.12%
Gas	Steam	0.00%	1.61%	1.61%
Landfill Gas	CT	0.00%	0.01%	0.01%
Municipal Waste	RICE	0.00%	0.01%	0.01%
Municipal Waste	Steam	0.00%	0.03%	0.03%
Oil	CC	0.00%	0.01%	0.01%
Oil	CT	1.01%	0.23%	1.23%
Oil	RICE	0.05%	0.00%	0.05%
Oil	Steam	0.00%	0.00%	0.00%
Other	Solar	0.00%	0.25%	0.25%
Other	Steam	0.00%	0.03%	0.03%
Uranium	Steam	0.00%	1.57%	1.57%
Wind	Solar	0.00%	0.00%	0.00%
Wind	Wind	0.05%	13.61%	13.65%
All Marginal Units		9.72%	90.28%	100.00%

Table 3-66 shows the fuel and technology used and technology where relevant, of marginal resources in the day-ahead energy market. In 2021, up to congestion transactions were 35.2 percent of marginal resources compared to 51.3 percent in 2020. In 2021, virtual transactions were 80.2 percent of marginal resources compared to 83.4 percent in 2020.[91]

91 The data for the September through December 2021 period is from the pricing run.

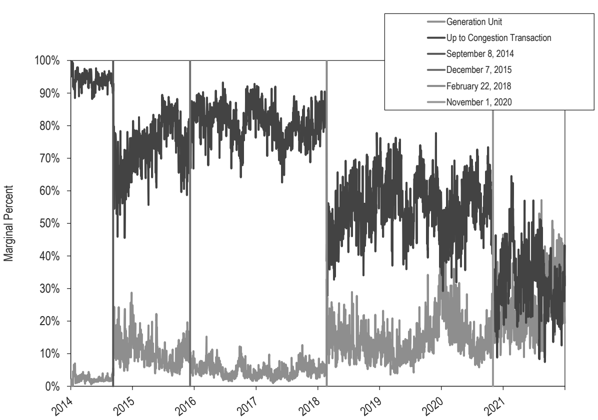
Table 3-66 Day-ahead marginal resources by type/fuel used and technology: 2017 through 2021

Type/Fuel	Technology	2017	2018	2019	2020	2021
Up to Congestion Transaction	NA	79.35%	62.30%	57.39%	51.34%	35.16%
DEC	NA	10.15%	16.90%	17.04%	18.79%	27.09%
INC	NA	5.49%	9.78%	12.76%	13.24%	17.91%
Gas	CC	2.10%	5.34%	7.42%	9.91%	11.26%
Coal	Steam	1.95%	4.63%	4.45%	5.12%	5.63%
Wind	Wind	0.15%	0.13%	0.10%	0.38%	1.26%
Gas	Steam	0.36%	0.28%	0.38%	0.47%	0.54%
Gas	CT	0.04%	0.20%	0.11%	0.21%	0.39%
Dispatchable Transaction	NA	0.04%	0.13%	0.10%	0.10%	0.27%
Gas	RICE	0.02%	0.04%	0.06%	0.05%	0.14%
Oil	CT	0.25%	0.04%	0.05%	0.10%	0.12%
Price Sensitive Demand	NA	0.00%	0.02%	0.00%	0.00%	0.06%
Uranium	Steam	0.08%	0.12%	0.10%	0.21%	0.04%
Other	Solar	0.00%	0.02%	0.01%	0.02%	0.04%
Municipal Waste	RICE	0.00%	0.01%	0.01%	0.01%	0.03%
Other	Steam	0.00%	0.01%	0.01%	0.04%	0.02%
Oil	RICE	0.01%	0.00%	0.00%	0.00%	0.02%
Oil	Steam	0.00%	0.04%	0.01%	0.01%	0.02%
Oil	CC	0.00%	0.02%	0.00%	0.00%	0.00%
Water	Hydro	0.01%	0.00%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-48 shows, for the day-ahead energy market from 2014 through 2021, the daily proportion of marginal resources that were up to congestion transactions and/or generation units. The UTC share decreased from 51.3 percent in 2020 to 35.2 percent in 2021.

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020.[92]

Figure 3-48 Day-ahead marginal up to congestion transaction and generation units: 2014 through 2021



Fuel Price Trends and LMP

In a competitive market, changes in LMP follow changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of short run marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs also contribute to changes in the marginal cost of marginal units.

Figure 3-49 shows fuel prices in PJM for 2012 through 2021. Natural gas prices increased in 2021 compared to 2020. Gas price volatility increased and gas price differences among regions increased. Western PJM gas prices were much higher in mid February than eastern PJM gas prices although both increased significantly. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM and a number of new combined cycle plants have located in the production area since 2016. In 2021, the price of production gas was 119.1 percent higher than in 2020, the price of eastern natural gas was 106.2 percent higher and the price of western natural gas was 143.3 percent higher. The price of Northern Appalachian coal was 42.3 percent higher; the price of Central Appalachian coal was 51.9 percent higher; and the price of Powder River Basin coal was 38.0 percent higher.[93] The price of ULSD NY Harbor Barge was 77.8 percent higher.

92 172 FERC ¶ 61,046 (2020).

93 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Figure 3-49 Spot average fuel price comparison: 2012 through 2021[94] ($/MMBtu)

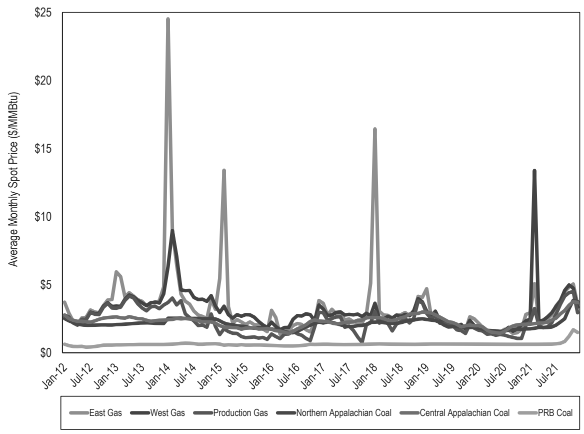


Table 3-67 compares the PJM real-time fuel-cost adjusted load-weighted average LMP in 2021 to the load-weighted average LMP in 2020.[95] The real-time load-weighted average LMP in 2021 increased by $18.02 per MWh or 82.8 percent from the real-time load-weighted average LMP in 2020. The real-time load-weighted average LMP for 2021 was 49.1 percent higher than the real-time fuel-cost adjusted load-weighted average LMP for 2021. The real-time fuel-cost adjusted load-weighted average LMP for 2021 was 22.6 percent higher than the real-time load-weighted average LMP for 2020. If fuel and emissions costs in 2021 had been the same as in 2020, holding the market dispatch constant, the real-time load-weighted average LMP in 2021 would have been lower, $26.68 per MWh, than the observed $39.78 per MWh. A significant portion, 72.7 percent, of the increase in real-time load-weighted average LMP, $13.11 per MWh out of $18.02 per MWh, is directly attributable to fuel costs. Contributors to the other $4.91 per MWh are increased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, and higher markups.

Starting on September 1, 2021, the fuel-cost adjusted load-weighted average LMP includes fuel cost associated with amortized start up and no load offers of the marginal fast start units in the pricing run.

94 This figure is modified from the corresponding figure in the *2020 Quarterly State of the Market Report for PJM: January through June*, which included an error.

95 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x costs.

Table 3-67 Real-time fuel-cost adjusted load-weighted average LMP (Dollars per MWh): 2020 and 2021

	2021 Fuel-Cost Adjusted, Load-Weighted LMP	2021 Load-Weighted LMP	Change	Percent Change
Average	$26.68	$39.78	$13.11	49.1%
	2020 Load-Weighted LMP	2021 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$21.77	$26.68	$4.91	22.6%
	2020 Load-Weighted LMP	2021 Load-Weighted LMP	Change	Change
Average	$21.77	$39.78	$18.02	82.8%

Table 3-68 shows the impact of each fuel type on the difference between the fuel-cost adjusted load-weighted average LMP and the load-weighted average LMP in 2021. Table 3-68 shows that lower natural gas prices explain 89.3 percent of the fuel-cost related decrease in the real-time annual load-weighted average LMP in 2021 from 2020.

Table 3-68 Share of change in fuel-cost adjusted LMP ($/MWh) by fuel type: 2021 adjusted to 2020 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Gas	$11.70	89.3%
Coal	$1.32	10.1%
Oil	$0.09	0.7%
Uranium	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Other	$0.00	0.0%
NA	$0.00	0.0%
Wind	$0.00	0.0%
Total	$13.11	100.0%

Components of LMP

Components of Real-Time Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and up to fourteen minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, New Jersey, and Virginia.[96] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and reserves. In periods of scarcity when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. In addition, in periods when the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

Starting on September 1, 2021, the components shown in Table 3-69 and Table 3-70 are from the pricing run which include the impact of amortized start cost and amortized no load cost of the fast start marginal units. The components of LMP are shown in Table 3-69, including markup using unadjusted cost-based offers.[97] Table 3-69 shows that in 2021, 10.3 percent of the load-weighted LMP was the result of coal costs, 53.9 percent was the result of gas costs and 2.7 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, negative markup was -5.0 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 9.2 percent of the load weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no cheaper generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. In 2021, 8.3 percent of the load-weighted LMP was the result of transmission penalty factors affecting LMPs. The percent contribution of transmission penalty factors was the highest since PJM removed constraint relaxation logic and allowed penalty factors to affect LMPs in February 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in 2021 and 2020.

96 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021.
97 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-69 Components of real-time (Unadjusted) load-weighted average LMP: 2020 and 2021

	2020		2021		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$9.03	41.5%	$21.43	53.9%	12.4%
Coal	$5.17	23.7%	$4.11	10.3%	(13.4%)
Positive Markup	$0.88	4.0%	$3.68	9.2%	5.2%
Constraint Violation Adder	$1.67	7.7%	$3.31	8.3%	0.7%
Ten Percent Adder	$1.68	7.7%	$2.54	6.4%	(1.3%)
NA	$0.91	4.2%	$1.51	3.8%	(0.4%)
Variable Maintenance	$1.34	6.2%	$1.36	3.4%	(2.8%)
CO_2 Cost	$0.37	1.7%	$1.08	2.7%	1.0%
Variable Operations	$0.84	3.9%	$0.84	2.1%	(1.7%)
Market-to-Market Adder	$0.00	0.0%	$0.41	1.0%	1.0%
Ancillary Service Redispatch Cost	$0.13	0.6%	$0.35	0.9%	0.3%
Oil	$0.07	0.3%	$0.25	0.6%	0.3%
Scarcity Adder	$0.08	0.4%	$0.22	0.6%	0.2%
NO_x Cost	$0.01	0.0%	$0.19	0.5%	0.5%
LPA Rounding Difference	$0.18	0.8%	$0.18	0.5%	(0.4%)
Opportunity Cost Adder	$0.07	0.3%	$0.16	0.4%	0.1%
Increase Generation Adder	$0.06	0.3%	$0.13	0.3%	0.0%
LPA-SCED Differential	$0.01	0.1%	$0.07	0.2%	0.1%
Other	$0.00	0.0%	$0.01	0.0%	0.0%
Landfill Gas	($0.00)	(0.0%)	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Renewable Energy Credits	($0.01)	(0.0%)	($0.03)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.02)	(0.1%)	($0.03)	(0.1%)	0.0%
Negative Markup	($0.72)	(3.3%)	($1.99)	(5.0%)	(1.7%)
Total	$21.77	100.0%	$39.78	100.0%	0.0%

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-69 and Table 3-73) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-70 and Table 3-74), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

The components of LMP are shown in Table 3-70, including markup using adjusted cost-based offers.

Table 3-70 Components of real-time (Adjusted) load-weighted average LMP: 2020 and 2021

	2020		2021		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$9.03	41.5%	$21.43	53.9%	12.4%
Positive Markup	$1.29	5.9%	$5.12	12.9%	6.9%
Coal	$5.17	23.7%	$4.11	10.3%	(13.4%)
Constraint Violation Adder	$1.67	7.7%	$3.31	8.3%	0.7%
NA	$1.83	8.4%	$1.51	3.8%	(4.6%)
Variable Maintenance	$1.34	6.2%	$1.36	3.4%	(2.8%)
CO_2 Cost	$0.37	1.7%	$1.08	2.7%	1.0%
Variable Operations	$0.84	3.9%	$0.84	2.1%	(1.7%)
Market-to-Market Adder	$0.00	0.0%	$0.41	1.0%	1.0%
Ancillary Service Redispatch Cost	$0.13	0.6%	$0.35	0.9%	0.3%
Oil	$0.07	0.3%	$0.25	0.6%	0.3%
Scarcity Adder	$0.08	0.4%	$0.22	0.6%	0.2%
NO_x Cost	$0.01	0.0%	$0.19	0.5%	0.5%
LPA Rounding Difference	$0.18	0.8%	$0.18	0.5%	(0.4%)
Opportunity Cost Adder	$0.07	0.3%	$0.16	0.4%	0.1%
Increase Generation Adder	$0.06	0.3%	$0.13	0.3%	0.0%
LPA-SCED Differential	$0.01	0.1%	$0.07	0.2%	0.1%
Other	$0.00	0.0%	$0.01	0.0%	0.0%
Landfill Gas	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Renewable Energy Credits	($0.01)	(0.0%)	($0.03)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.02)	(0.1%)	($0.03)	(0.1%)	0.0%
Negative Markup	($0.37)	(1.7%)	($0.89)	(2.2%)	(0.5%)
Total	$21.77	100.0%	$39.78	100.0%	0.0%

PJM implemented fast start pricing on September 1, 2021. The commitment cost related components of LMP are shown in Table 3-71, including markup using unadjusted cost-based offers for September 1 through December 31, 2021. In the first four months of fast start pricing in PJM, 3.4 percent of the load-weighted average LMP was the result of commitment costs. The majority of the commitment costs in LMP were fuel costs in the no load component of offers for gas-fired fast start units. The second largest component was maintenance costs.

Table 3-71 Commitment cost related components of real-time (Unadjusted) load-weighted average LMP: September through December, 2021

	Commitment Components		Other Components		Total	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
Gas	$1.30	2.5%	$27.39	52.5%	$28.69	55.0%
Postive Markup	$0.14	0.3%	$5.37	10.3%	$5.51	10.6%
Constraint Violation Adder	$0.00	0.0%	$3.77	7.2%	$3.77	7.2%
Coal	$0.00	0.0%	$3.59	6.9%	$3.59	6.9%
Ten Percent Adder	$0.14	0.3%	$3.04	5.8%	$3.18	6.1%
NA	$0.00	0.0%	$3.14	6.0%	$3.14	6.0%
Variable Maintenance	$0.41	0.8%	$1.40	2.7%	$1.81	3.5%
Market-to-Market Adder	$0.00	0.0%	$1.30	2.5%	$1.30	2.5%
CO_2 Cost	$0.01	0.0%	$1.27	2.4%	$1.28	2.4%
Variable Operations	$0.00	0.0%	$0.82	1.6%	$0.82	1.6%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.43	0.8%	$0.43	0.8%
LPA Rounding Difference	$0.00	0.0%	$0.41	0.8%	$0.41	0.8%
Opportunity Cost Adder	$0.00	0.0%	$0.28	0.5%	$0.28	0.5%
Increase Generation Adder	$0.00	0.0%	$0.19	0.4%	$0.19	0.4%
Oil	$0.00	0.0%	$0.11	0.2%	$0.11	0.2%
Scarcity Adder	$0.00	0.0%	$0.09	0.2%	$0.09	0.2%
NO_x Cost	$0.00	0.0%	$0.07	0.1%	$0.07	0.1%
Other	$0.00	0.0%	$0.01	0.0%	$0.01	0.0%
Landfill Gas	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
LPA-SCED Differential	$0.00	0.0%	($0.00)	(0.0%)	($0.00)	(0.0%)
Decrease Generation Adder	$0.00	0.0%	($0.04)	(0.1%)	($0.04)	(0.1%)
Renewable Energy Credits	$0.00	0.0%	($0.10)	(0.2%)	($0.10)	(0.2%)
Negative Markup	($0.21)	(0.4%)	($2.14)	(4.1%)	($2.35)	(4.5%)
Total	$1.80	3.4%	$50.40	96.6%	$52.20	100.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-72, including markup using unadjusted cost-based offers for the first four months of fast start pricing in PJM.

Table 3-72 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: September through December, 2021

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$26.69	53.9%	$28.69	55.0%	1.0%
Positive Markup	$5.39	10.9%	$5.51	10.6%	(0.3%)
Constraint Violation Adder	$3.74	7.6%	$3.77	7.2%	(0.3%)
Coal	$3.88	7.8%	$3.59	6.9%	(1.0%)
Ten Percent Adder	$2.98	6.0%	$3.18	6.1%	0.1%
NA	$2.92	5.9%	$3.14	6.0%	0.1%
Variable Maintenance	$1.27	2.6%	$1.81	3.5%	0.9%
Market-to-Market Adder	$1.17	2.4%	$1.30	2.5%	0.1%
CO_2 Cost	$1.45	2.9%	$1.28	2.4%	(0.5%)
Variable Operations	$0.72	1.5%	$0.82	1.6%	0.1%
Ancillary Service Redispatch Cost	$0.25	0.5%	$0.43	0.8%	0.3%
LPA Rounding Difference	$0.39	0.8%	$0.41	0.8%	0.0%
Opportunity Cost Adder	$0.22	0.4%	$0.28	0.5%	0.1%
Increase Generation Adder	$0.14	0.3%	$0.19	0.4%	0.1%
Oil	$0.06	0.1%	$0.11	0.2%	0.1%
Scarcity Adder	$0.14	0.3%	$0.09	0.2%	(0.1%)
NO_x Cost	$0.08	0.2%	$0.07	0.1%	(0.0%)
Other	$0.01	0.0%	$0.01	0.0%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Adder	($0.04)	(0.1%)	($0.04)	(0.1%)	0.0%
Renewable Energy Credits	($0.09)	(0.2%)	($0.10)	(0.2%)	0.0%
Negative Markup	($1.89)	(3.8%)	($2.35)	(4.5%)	(0.7%)
Total	$49.47	100.0%	$52.20	100.0%	0.0%

Components of Day-Ahead Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

PJM implemented fast start pricing on September 1, 2021 in the day-ahead market as well. The marginal resources and sensitivity factors are different between the dispatch run and pricing run. Since PJM uses LMPs generated in the pricing run as settlement LMPs, in Table 3-73 and Table 3-74, the components of day-ahead load-weighted average LMP in September through December, 2021 are calculated using marginal resource and sensitivity factor data from the pricing run and original data is used in 2020 and the first eight months of 2021.

Table 3-73 shows the components of the PJM day-ahead annual load-weighted average LMP. In 2021, 25.9 percent of the load-weighted LMP was the result of gas costs, 11.2 percent of the load-weighted LMP was the result of coal costs, 29.7 percent was the result of DECs, 17.2 percent was the result of INCs and 0.8 percent was the result of UTCs.

Table 3-73 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): 2020 and 2021

	2020		2021		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$5.13	24.0%	$11.70	29.7%	5.8%
Gas	$4.11	19.2%	$10.21	25.9%	6.8%
INC	$3.25	15.2%	$6.76	17.2%	2.0%
Coal	$5.37	25.1%	$4.42	11.2%	(13.9%)
Positive Markup	$0.95	4.4%	$2.24	5.7%	1.3%
Ten Percent Adder	$1.12	5.2%	$1.51	3.8%	(1.4%)
Variable Maintenance	$0.86	4.0%	$0.78	2.0%	(2.0%)
CO_2 Cost	$0.23	1.1%	$0.77	2.0%	0.9%
Variable Operations	$0.63	3.0%	$0.65	1.7%	(1.3%)
Dispatchable Transaction	$0.05	0.2%	$0.58	1.5%	1.3%
Up to Congestion Transaction	$0.64	3.0%	$0.32	0.8%	(2.2%)
Oil	$0.02	0.1%	$0.19	0.5%	0.4%
NO_x Cost	$0.01	0.1%	$0.19	0.5%	0.4%
Price Sensitive Demand	$0.01	0.1%	$0.17	0.4%	0.4%
Municipal Waste	$0.00	0.0%	$0.01	0.0%	0.0%
Opportunity Cost Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Other	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Station Service Charges	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.00)	(0.0%)	($0.13)	(0.3%)	(0.3%)
Negative Markup	($0.98)	(4.6%)	($1.02)	(2.6%)	2.0%
NA	$0.01	0.0%	$0.01	0.0%	(0.0%)
Total	$21.40	100.0%	$39.37	100.0%	(0.0%)

Table 3-74 shows the components of the PJM day-ahead annual load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units.

Table 3-74 Components of day-ahead (Adjusted) load-weighted average LMP (Dollars per MWh): 2020 and 2021

	2020		2021		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$5.13	24.0%	$11.70	29.7%	5.8%
Gas	$4.11	19.2%	$10.06	25.5%	6.4%
INC	$3.25	15.2%	$6.76	17.2%	2.0%
Coal	$5.37	25.1%	$4.40	11.2%	(13.9%)
Positive Markup	$1.59	7.4%	$3.37	8.5%	1.1%
Variable Maintenance	$0.86	4.0%	$0.77	2.0%	(2.1%)
CO_2 Cost	$0.23	1.1%	$0.77	2.0%	0.9%
Variable Operations	$0.63	3.0%	$0.65	1.7%	(1.3%)
Dispatchable Transaction	$0.05	0.2%	$0.58	1.5%	1.3%
Up to Congestion Transaction	$0.64	3.0%	$0.32	0.8%	(2.2%)
Oil	$0.02	0.1%	$0.19	0.5%	0.4%
NO_x Cost	$0.01	0.1%	$0.19	0.5%	0.4%
Price Sensitive Demand	$0.01	0.1%	$0.17	0.4%	0.4%
Municipal Waste	$0.00	0.0%	$0.01	0.0%	0.0%
Opportunity Cost Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Other	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Station Service Charges	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Ten Percent Adder	$0.00	0.0%	($0.01)	(0.0%)	(0.1%)
Wind	($0.00)	(0.0%)	($0.13)	(0.3%)	(0.3%)
Negative Markup	($0.50)	(2.4%)	($0.44)	(1.1%)	1.2%
NA	$0.01	0.0%	$0.01	0.0%	(0.0%)
Total	$21.40	100.0%	$39.37	100.0%	0.0%

PJM implemented fast start pricing on September 1, 2021 and amortized startup cost and no load cost were included in the price offers of fast start marginal units. The commitment cost related components of LMP are used to capture the amortized startup cost and no load cost of the fast start marginal units. Table 3-75 shows that in September through December 2021, 0.4 percent of the load-weighted average LMP was the result of commitment costs using unadjusted cost-based offers. Table 3-76 shows the commitment cost related components of LMP using adjusted cost-based offers for September through December 2021.

Table 3-75 Commitment cost related components of day-ahead (Unadjusted) load-weighted average LMP: September through December, 2021

	Commitment		Other		All Generation		Virtuals and Transactions		Total	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
DEC	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$14.99	29.7%	$14.99	29.7%
Gas	$0.13	0.3%	$12.48	24.7%	$12.61	25.0%	$0.00	0.0%	$12.61	25.0%
INC	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$11.71	23.2%	$11.71	23.2%
Coal	$0.00	0.0%	$4.31	8.5%	$4.31	8.5%	$0.00	0.0%	$4.31	8.5%
Positive Markup	$0.00	0.0%	$3.34	6.6%	$3.34	6.6%	$0.00	0.0%	$3.34	6.6%
Ten Percent Adder	$0.02	0.0%	$1.81	3.6%	$1.83	3.6%	$0.00	0.0%	$1.83	3.6%
CO_2 Cost	$0.00	0.0%	$0.86	1.7%	$0.86	1.7%	$0.00	0.0%	$0.86	1.7%
Variable Maintenance	$0.02	0.0%	$0.75	1.5%	$0.77	1.5%	$0.00	0.0%	$0.77	1.5%
Dispatchable Transaction	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.59	1.2%	$0.59	1.2%
Variable Operations	($0.00)	(0.0%)	$0.55	1.1%	$0.55	1.1%	$0.00	0.0%	$0.55	1.1%
Oil	$0.00	0.0%	$0.19	0.4%	$0.20	0.4%	$0.00	0.0%	$0.20	0.4%
Price Sensitive Demand	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.16	0.3%	$0.16	0.3%
NO_x Cost	($0.00)	(0.0%)	$0.10	0.2%	$0.09	0.2%	$0.00	0.0%	$0.09	0.2%
Opportunity Cost Adder	$0.00	0.0%	$0.01	0.0%	$0.01	0.0%	$0.00	0.0%	$0.01	0.0%
Municipal Waste	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Station Service Charges	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Wind	$0.00	0.0%	($0.12)	(0.2%)	($0.12)	(0.2%)	$0.00	0.0%	($0.12)	(0.2%)
Up to Congestion Transaction	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	($0.55)	(1.1%)	($0.55)	(1.1%)
Negative Markup	$0.01	0.0%	($0.93)	(1.8%)	($0.92)	(1.8%)	$0.00	0.0%	($0.92)	(1.8%)
NA	$0.00	0.0%	$0.00	0.0%	$0.02	0.0%	$0.00	0.0%	$0.02	0.0%
Total	$0.19	0.4%	$23.34	46.3%	$23.55	46.7%	$26.90	53.3%	$50.44	100.0%

Table 3-76 Commitment cost related components of day-ahead (Adjusted) load-weighted average LMP: September through December, 2021

	Commitment		Other		All Generation		Virtuals and Transactions		Total	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
DEC	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$14.99	29.7%	$14.99	29.7%
Gas	$0.13	0.3%	$12.37	24.5%	$12.51	24.8%	$0.00	0.0%	$12.51	24.8%
INC	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$11.71	23.2%	$11.71	23.2%
Positive Markup	$0.02	0.0%	$4.65	9.2%	$4.67	9.3%	$0.00	0.0%	$4.67	9.3%
Coal	$0.00	0.0%	$4.31	8.5%	$4.31	8.5%	$0.00	0.0%	$4.31	8.5%
CO_2 Cost	$0.00	0.0%	$0.86	1.7%	$0.86	1.7%	$0.00	0.0%	$0.86	1.7%
Variable Maintenance	$0.02	0.0%	$0.75	1.5%	$0.77	1.5%	$0.00	0.0%	$0.77	1.5%
Dispatchable Transaction	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.59	1.2%	$0.59	1.2%
Variable Operations	($0.00)	(0.0%)	$0.55	1.1%	$0.55	1.1%	$0.00	0.0%	$0.55	1.1%
Oil	$0.01	0.0%	$0.19	0.4%	$0.20	0.4%	$0.00	0.0%	$0.20	0.4%
Price Sensitive Demand	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.16	0.3%	$0.16	0.3%
NO_x Cost	($0.00)	(0.0%)	$0.09	0.2%	$0.09	0.2%	$0.00	0.0%	$0.09	0.2%
Opportunity Cost Adder	$0.00	0.0%	$0.01	0.0%	$0.01	0.0%	$0.00	0.0%	$0.01	0.0%
Municipal Waste	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Station Service Charges	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Ten Percent Adder	$0.00	0.0%	($0.01)	(0.0%)	($0.01)	(0.0%)	$0.00	0.0%	($0.01)	(0.0%)
Wind	$0.00	0.0%	($0.12)	(0.2%)	($0.12)	(0.2%)	$0.00	0.0%	($0.12)	(0.2%)
Negative Markup	$0.01	0.0%	($0.33)	(0.7%)	($0.32)	(0.6%)	$0.00	0.0%	($0.32)	(0.6%)
Up to Congestion Transaction	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	($0.55)	(1.1%)	($0.55)	(1.1%)
NA	$0.00	0.0%	$0.00	0.0%	$0.02	0.0%	$0.00	0.0%	$0.02	0.0%
Total	$0.19	0.4%	$23.34	46.3%	$23.55	46.7%	$26.90	53.3%	$50.44	100.0%

Table 3-77 compares the components of LMP between the dispatch run and the pricing run for September 1 through December 31, 2021. The marginal resources and sensitivity factors are different between the dispatch run and pricing run. The dispatch run components of day-ahead load-weighted average LMP are calculated using the marginal resources and sensitivity factors from the dispatch run result and the pricing run components of day-ahead, load-weighted, average LMP are calculated using the marginal resources and sensitivity factors from the pricing run result. The marginal DEC contribution of day-ahead load-weighted LMP decreased 1.7 percent, the marginal gas generation unit contribution of day-ahead load-weighted average LMP decreased 0.8 percent and the marginal INC contribution of day-ahead load-weighted average LMP increased 7.3 percent from the dispatch run to the pricing run. Table 3-78 compares components of the PJM day-ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units between the dispatch run and the pricing run.

Table 3-77 Components of day-ahead (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: September through December, 2021

	Dispatch Run		Pricing Run		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$15.80	31.4%	$14.99	29.7%	(1.7%)
Gas	$12.99	25.8%	$12.61	25.0%	(0.8%)
INC	$8.01	15.9%	$11.71	23.2%	7.3%
Coal	$4.43	8.8%	$4.31	8.5%	(0.3%)
Positive Markup	$3.97	7.9%	$3.34	6.6%	(1.3%)
Ten Percent Adder	$1.66	3.3%	$1.83	3.6%	0.3%
CO_2 Cost	$0.94	1.9%	$0.86	1.7%	(0.2%)
Variable Maintenance	$0.74	1.5%	$0.77	1.5%	0.0%
Dispatchable Transaction	$0.61	1.2%	$0.59	1.2%	(0.0%)
Variable Operations	$0.57	1.1%	$0.55	1.1%	(0.1%)
Oil	$0.00	0.0%	$0.20	0.4%	0.4%
Price Sensitive Demand	$0.22	0.4%	$0.16	0.3%	(0.1%)
NO_x Cost	$0.07	0.1%	$0.09	0.2%	0.0%
Opportunity Cost Adder	$0.01	0.0%	$0.01	0.0%	0.0%
Municipal Waste	$0.02	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
Station Service Charges	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.18)	(0.3%)	($0.12)	(0.2%)	0.1%
Up to Congestion Transaction	$1.45	2.9%	($0.55)	(1.1%)	(4.0%)
Negative Markup	($1.06)	(2.1%)	($0.92)	(1.8%)	0.3%
NA	$0.00	0.0%	$0.02	0.0%	0.0%
Total	$50.28	100.0%	$50.44	100.0%	(0.0%)

Table 3-78 Components of day-ahead (Adjusted) load-weighted average LMP in the dispatch run and pricing run: September through December, 2021

	Dispatch Run		Pricing Run		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$15.80	31.4%	$14.99	29.7%	(1.7%)
Gas	$12.77	25.4%	$12.51	24.8%	(0.6%)
INC	$8.01	15.9%	$11.71	23.2%	7.3%
Positive Markup	$5.32	10.6%	$4.67	9.3%	(1.3%)
Coal	$4.39	8.7%	$4.31	8.5%	(0.2%)
CO_2 Cost	$0.94	1.9%	$0.86	1.7%	(0.1%)
Variable Maintenance	$0.73	1.5%	$0.77	1.5%	0.1%
Dispatchable Transaction	$0.61	1.2%	$0.59	1.2%	(0.0%)
Variable Operations	$0.57	1.1%	$0.55	1.1%	(0.0%)
Oil	$0.00	0.0%	$0.20	0.4%	0.4%
Price Sensitive Demand	$0.22	0.4%	$0.16	0.3%	(0.1%)
NO_x Cost	$0.07	0.1%	$0.09	0.2%	0.0%
Opportunity Cost Adder	$0.01	0.0%	$0.01	0.0%	0.0%
Municipal Waste	$0.02	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
Station Service Charges	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Ten Percent Adder	($0.02)	(0.0%)	($0.01)	(0.0%)	0.0%
Wind	($0.18)	(0.3%)	($0.12)	(0.2%)	0.1%
Negative Markup	($0.46)	(0.9%)	($0.32)	(0.6%)	0.3%
Up to Congestion Transaction	$1.45	2.9%	($0.55)	(1.1%)	(4.0%)
NA	$0.00	0.0%	$0.02	0.0%	0.0%
Total	$50.28	100.0%	$50.44	100.0%	0.0%

Shortage

PJM's energy market experienced five minute shortage pricing for 28 five minute intervals on 14 days in 2021. PJM implemented fast start pricing on September 1, 2021. From September 2021 through December 2021, there were 11 five minute intervals with shortage pricing, and there were no differences in the shortage pricing results from the dispatch and pricing run during these 11 intervals. Table 3-79 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in 2020 and 2021. In 2021, there were no emergency actions that triggered a Performance Assessment Interval (PAI). The days with shortage pricing intervals did not correspond to the days with emergency alerts.

Table 3-79 Summary of emergency events declared: 2020 and 2021

	Number of days events declared	
Event Type	2020	2021
Cold Weather Alert	3	6
Hot Weather Alert	19	23
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	6	14
Energy export recalls from PJM capacity resources	0	0

Figure 3-50 shows the number of days that weather and capacity emergency alerts were issued in PJM from 2012 through 2021.

Figure 3-50 Declared emergency alerts: 2012 through 2021

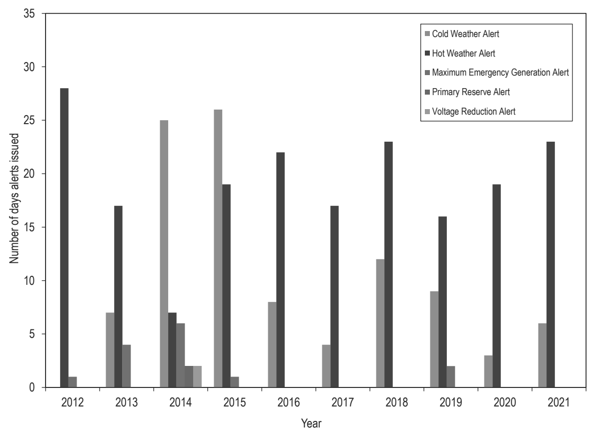
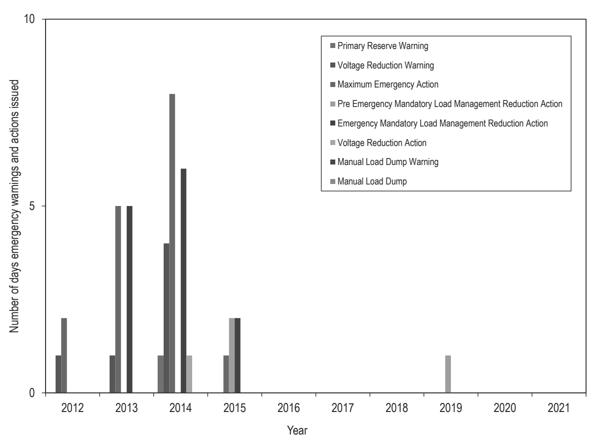


Figure 3-51 shows the number of days that emergency warnings and actions were declared in PJM from 2012 through 2021.

Figure 3-51 Declared emergency warnings and actions: 2012 through 2021



Emergency Procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time, on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

Table 3-80 provides a description of PJM declared emergency procedures.[98] [99] [100] [101]

Table 3-80 Description of emergency procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members that a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
Voltage Reduction Action	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

98 See PJM. "Manual 13: Emergency Operations," Rev. 83 (Jan. 26, 2022), Section 3.3 Cold Weather Alert.
99 See PJM. "Manual 13: Emergency Operations," Rev. 83 (Jan. 26, 2022), Section 3.4 Hot Weather Alert.
100 See PJM. "Manual 13: Emergency Operations," Rev. 83 (Jan. 26, 2022), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
101 See PJM. "Manual 13: Emergency Operations," Rev. 83 (Jan. 26, 2022), Section 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-81 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2021.

Table 3-81 Declared emergency alerts, warnings and actions: 2021

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
2/7/2021	Western except EKPC													
2/8/2021	Western except EKPC													
2/9/2021	COMED													
2/10/2021	COMED													
2/14/2021	COMED													
2/15/2021	Western													
5/23/2021		Mid-Atlantic and Southern												
6/6/2021		Mid-Atlantic												
6/7/2021		Mid-Atlantic												
6/28/2021		RTO except COMED												
6/29/2021		RTO except COMED												
6/30/2021		Mid-Atlantic and Southern												
7/6/2021		RTO												
7/7/2021		Mid-Atlantic and Southern												
7/15/2021		Mid-Atlantic and Southern												
7/16/2021		Mid-Atlantic and Southern												
7/17/2021		Mid-Atlantic and Southern												
7/27/2021		Mid-Atlantic												
8/9/2021		Mid-Atlantic and Western except COMED												
8/10/2021		Mid-Atlantic and COMED												
8/11/2021		RTO												
8/12/2021		RTO												
8/13/2021		Mid-Atlantic and Southern												
8/24/2021		RTO												
8/25/2021		RTO												
8/26/2021		RTO except COMED												
8/27/2021		Mid-Atlantic and Southern												
9/14/2021		Mid-Atlantic and Southern												
9/15/2021		Mid-Atlantic												

Power Balance Constraint Violation

On October 1, 2019, the power balance constraint was violated in 11 approved RT SCED solutions. On February 16, 2020, the power balance constraint was violated in one approved RT SCED solution which was used to set prices for three five minute intervals. On March 22, 2021, the power balance constraint was violated in one approved RT SCED solution. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand. In some cases, the power balance constraint is violated while the reserve requirements are satisfied.

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM would convert reserves to energy before violating power balance. It is unclear whether and when PJM would use its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by ASO to energy to satisfy the power balance constraint.[102] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described, is not consistent

102 Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

with basic economics. The overall solution is complex and must be integrated with the approach to shortage pricing.

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding.The average energy component of LMP in that five minute interval with artificially increased supply to satisfy the power balance constraint was $1,582.14 per MWh.

Table 3-82 shows the number of five minute intervals for which the RT SCED solutions used to set prices did not balance demand and supply. PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In 2021, there were three five minute intervals using an RT SCED solution with a violated power balance constraint. The average energy component of LMP in that five minute interval with artificially increased supply to satisfy the power balance constraint was $1,582.14 per MWh.[103]

Table 3-82 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP ($/MWh)
2013	-	$0.00
2014	655	$36.29
2015	71	($0.76)
2016	42	$93.06
2017	31	$279.86
2018	16	$268.21
2019	36	$845.48
2020	5	$351.56
2021	3	$1,582.14

Balancing Ratio for Local Emergency Events

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements in an area during an emergency event to the total committed capacity in the area. In the case of the PAIs declared in 2018 that were triggered due to transmission outages in limited locations, if the area is defined as the location where the load was shed, the balancing ratio is undefined because there were no committed resources in the area, other than less than 1.0 MW of demand response.[104] It is not appropriate or correct to calculate a balancing ratio as a measure of capacity needed during these events by defining a wider area to include committed capacity. It is also not appropriate to use a balancing ratio defined in that way in defining the capacity market offer cap. PJM calculated the balancing ratio for the localized load shed that occurred in the AEP Edison area in 2018 and used the average balancing ratio during the event to calculate the capacity market seller offer cap for all LDAs for the 2022/2023 Delivery Year.[105] These events occurred in a very small local area where no capacity resources were held to CP performance requirements. Assessing nonperformance to resources located in the wider area would not be appropriate because their performance would not have helped, and may have even exacerbated the transmission issues identified during these events. These events also do not reflect the type of events that are modeled to define the target installed reserve margin in the capacity market. The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level.

Performance Assessment Intervals

PJM currently triggers a PAI any time it declares a pre-emergency load management reduction action, or a more severe emergency action.[106] PJM's trigger for PAI is subjective, and it should be based on a quantifiable, transparent metric of the need for capacity in the PJM system. For example, in ISO New England, under the Pay for Performance design, resources are assessed for performance during Capacity Scarcity Conditions ("CSCs") that occur when the system or local area is

103 The energy component of LMP, or the shadow price of the power balance constraint, is the incremental cost of meeting a one MWh increase in the system load.

104 See *2018 State of the Market Report for PJM*, Volume II, Section 3: Energy Market, at Scarcity, pp. 201 – 202.

105 *See* PJM, "Capacity Market Seller Offer Cap Values," (March 15, 2019), which can be accessed at <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-cp-market-seller-offer-cap-values.ashx?la=en?>.

106 OATT Definitions at "Emergency Action."

short on ten and thirty minute nonspinning reserves.[107] Reserve shortages are determined based on a predefined reserve requirement, and the reserve calculation that is embedded in the real-time dispatch tool.

The October 2, 2019, PAI provided actual data and evidence on the issues with PJM's triggers, and PJM's treatment of excused MW. The PAI on October 2, 2019, was triggered when PJM declared a pre-emergency load management reduction action in the AEP, BGE, DOM and PEPCO Zones based on anticipated high load relative to the available supply. The actual load was significantly lower than forecasted.[108]

On October 1, 2019, the day before the PAI, PJM did experience high load relative to the available supply. The system conditions were reflected in the market outcomes with multiple intervals of high prices, and reserve shortages.[109] The decision to declare a pre-emergency load management reduction action on October 2, 2019, was based on an expectation of the repetition of the events on October 1, 2019, which did not materialize. This illustrates the shortcomings of triggering PAIs based on PJM operator declared emergency actions or pre-emergency load management reduction, instead of using a quantitative metric that is readily available to PJM, such as reserves.[110] Given this implementation, it can no longer be assumed that PAI would occur when the PJM region, or a subset of zones in the PJM region are experiencing capacity shortage conditions.

Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling scarcity conditions through high energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage shortage pricing and made it difficult to distinguish between market power and shortage pricing. Shortage pricing is an administrative pricing mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real-time reserves than required.

In 2021, there were 28 five minute intervals with shortage pricing that occurred on 14 days in PJM.

With Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[111] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. PJM did not implement the rule as intended in Order No. 825, because RT SCED can indicate a shortage that PJM does not use in pricing. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes, from the previous three minutes. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to match the frequency of pricing at five minutes, which reduced the frequency of unpriced shortage solutions. Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC that

107 ISO New England Inc. Internal Market Monitor, "2018 Annual Markets Report," (May 23, 2019) at 156 (§ 6.2.2 (Pay-for-Performance Outcomes)).

108 In a report reviewing the PAI, PJM stated: "The most striking anomaly was load levels in the AEP and Mid-Atlantic zones that came in significantly below forecast." *See* PJM, "A Review of the October 2019 Performance Assessment Event," (2019) at 1, which can be accessed at <https://www.pjm.com/-/media/markets-ops/rpm/review-of-october-2019-performance-assessment-event.ashx>.

109 *See* Monitoring Analytics, LLC, *2019 State of the Market Report for PJM*, Volume II: Section 3 Energy Market at 176 –180 (Analysis of October 1 Events).

110 There are existing issues with the accuracy of reserve measurement in PJM, and they should also be resolved by improving generator modeling in the energy market.

111 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).

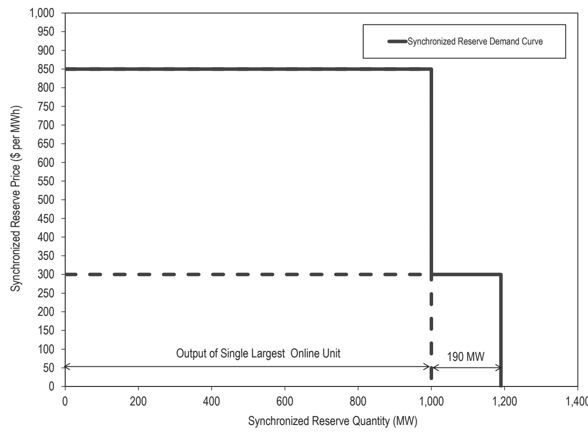
incorporates integer relaxation for certain units deemed fast start by PJM. This can lead to differences between the dispatched reserves in RT SCED, and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing may be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data do not show a shortage of reserves.[112]

Operating Reserve Demand Curves

Since July 12, 2017, the PJM synchronized reserve requirement in a reserve zone or a subzone is the actual output of the single largest online unit in that reserve zone or subzone. The primary reserve requirement in a reserve zone or a subzone is 150 percent of the actual output of the single largest online unit in that reserve zone or subzone. The first step of the demand curves for primary and synchronized reserves are set at the primary and synchronized reserve requirement. Since the primary and synchronized reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step is priced at $850 per MWh. The second step of the primary and synchronized reserve demand curves extends the primary and synchronized reserve requirements. The extended primary and synchronized reserve requirements are defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 3-52 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region equals 1,000 MW.

Figure 3-52 Real-time synchronized reserve demand curve showing the permanent second step



Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-52 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh.

The shortage prices set by the ORDC are added to LMP during shortages. When multiple reserve products are short or when reserves are short in multiple zones, the ORDC prices are additive. Currently, the highest possible shortage penalty in LMP is $3,400 per MWh, which is the $850 per MWh price times four, for two reserve products (synchronized reserve and nonsynchronized reserve) times two reserve zones, RTO and MAD. However, PJM caps the system marginal energy price at $3,750, which is the sum of the highest possible energy offer, the synchronized reserve penalty factor, the primary reserve penalty factor, and a $50 per MWh threshold. The current market rules cap the additive reserve shortage penalty factors for the MAD synchronized reserve market clearing price to the sum of the synchronized reserve penalty factor and the primary reserve penalty

112 *See, e.g.*, Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21–30:14 (Oct. 28, 2014).

factor, which is $1,700 per MW.[113] The $1,700 per MWh penalty applies any time PJM initiates a manual load dump action or voltage reduction action.[114]

Energy and Reserve Price Caps

Table 3-83 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a $1,700 per MWh reserve shortage penalty in the RTO zone LMP and a $3,400 per MWh reserve shortage penalty in the MAD Zone LMP. The marginal resource for energy is in the RTO Zone, and the RTO to MAD reserve transfer constraint is not binding, so the higher MAD reserve penalty does not affect the rest of RTO LMP. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a violated transmission constraint that affects the marginal congestion costs in the system marginal price.

In scenario C, the sum of the reserve and transmission constraint penalty factors equals $5,450 per MWh, which exceeds $3,750 per MWh, so SMP capping is triggered whether the marginal unit for energy can provide reserves for the MAD Zone or only the RTO Zone.

In scenario D, with a $1,000 per MWh offer price for the marginal unit for energy, violation of all four reserve penalty factors only triggers SMP capping if the marginal unit for energy can serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed $3,750 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.[115]

In Scenario F, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in the $1,700 per MWh scarcity adder, and a violated transmission constraint with $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario F are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple violated transmission constraints, the congestion costs contributing to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint.

Table 3-83 Real-time additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

		Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		Transmission Constraint	System Marginal Price		Transmission Constraint	Total LMP	
Scenario	Marginal Unit Offer Price	RTO	MAD	RTO	MAD	Penalty Factor in SMP	RTO Marginal	MAD Marginal	Penalty Factor in CLMP	RTO Marginal	MAD Marginal
A	$50	$850	$0	$0	$0	$0	$900	$900	$0	$900	$900
B	$50	$850	$850	$850	$850	$0	$1,750	$3,450	$0	$1,750	$3,450
C	$50	$850	$850	$850	$850	$2,000	$3,750	$3,750	$0	$3,750	$3,750
D	$1,000	$850	$850	$850	$850	$0	$2,700	$3,750	$0	$2,700	$3,750
E	$1,000	$850	$850	$850	$850	$2,000	$3,750	$3,750	$2,000	$5,750	$5,750
F	$2,000	$850	$850	$850	$850	$2,000	$3,750	$3,750	$2,000	$5,750	$5,750

113 *See* PJM Operating Agreement, Schedule 1, Section 3.2.3A(d)(ii). The cap on the additive reserve shortage penalty factors in MAD was not reflected in the prior report and the maximum in MAD was therefore overstated. See: *2020 Quarterly State of the Market Report for PJM: January through September*, p. 192.

114 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 117 (Nov. 1, 2021), 2.8 The Calculation of Locational Marginal Prices (LMPs) During Emergency Procedures.

115 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

Changes to the ORDC, previously approved by FERC and planned for implementation in 2022, were reversed by the Commission in an order issued on December 22, 2021.[116] These changes, if implemented, would have increased the price for reserve quantities less than the reserve requirement to $2,000 per MWh, and prices beyond the reserve requirement to levels that were based on an extended downward sloping ORDC, and the price cap would have been removed.[117]

Circuit Breaker

Due to the high prices that were possible under PJM's proposed ORDCs and the February 2021 experiences of market participants in the ERCOT market, PJM stakeholders initiated a discussion about a circuit breaker mechanism that would use lower transmission constraint penalty prices and lower reserve penalty prices during extended emergency situations. While FERC's remand order maintains the current levels of emergency pricing, rather than PJM's higher proposed levels, there remain possible scenarios in which prolonged and excessively high administrative pricing in the energy market under the current tariff provisions would impose inefficient wealth transfers. Inefficient wealth transfers from load to generation, among generators, or from physical to financial market participants occur when administrative pricing creates arbitrarily high price signals to which participants cannot respond.

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserve prices. The need to commit more reserves could instead be directly reflected in the ORDC when operational issues arise, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets.

Locational Reserve Requirements

In addition to the construction of the operating reserve demand curves to reflect the value of maintaining reserves and avoiding a loss of load event, the modeling of reserve requirements should reflect locational needs and should price operator actions to, for example, commit more reserves when specific needs arise.

The current operating reserve demand curves are modeled for reserve requirements for the RTO level (RTO Reserve Zone) and for the Mid-Atlantic and Dominion region (MAD Subzone). This was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. On most days, the MAD Subzone is no longer relevant. PJM may need to maintain or operate resources in other local areas to maintain local reliability. Currently, these units are committed out of market for reliability reasons, or the reserve need is modeled as an artificial closed loop interface with limited deliverability modeled inside the closed loop from resources located outside. The value of operating these resources, including generators that are manually committed for reliability and demand resources that may be dispatched inside a closed loop, is not correctly reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies.

Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. Currently, spinning events are triggered by an all call message to the system requesting all online generation units to increase their energy output, regardless of whether a unit cleared for synchronized reserves. This deployment mechanism is used regardless of the actual MW needed to recover the Area Control Error (ACE) to zero or to the pre-event levels. Generally, the cause of the spinning event is a unit trip. Occasionally, PJM also declares spinning events to recover ACE when generators do not follow dispatch instructions to increase output. The response solicited through the all call message during a spinning event is much greater than the MW lost and MW needed to recover the ACE. This results in an overshoot of the ACE to positive values beyond the target range. There is currently no mechanism for PJM to selectively load synchronized reserves in proportion to the MW needed to recover ACE to zero or the pre-event levels, even though the PJM market rules allow PJM to load a proportion of reserves. While the all-call message signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load

116 177 FERC ¶ 61,209 (December 22, 2021).
117 See 171 FERC ¶ 61,153 (2020), *order on reh'g*, 173 FERC ¶ 61,123 (2020).

and reserve requirements ten to fourteen minutes into the future. This results in a discrepancy between the operational need during a spinning event, and the RT SCED solutions. PJM's instruction to generators is to ignore the dispatch signals sent by RT SCED, and instead continue to ramp their units up until the spin event ends. Since the LMPs do not reflect the need for the generators to ramp up their resources, PJM currently pays a $50 per MWh premium to all resources, except Tier 2 cleared resources, that increase their output in response to a spinning event.

Under the reserve market enhancements that are planned for October 2022, all synchronized reserves are treated as a uniform product and paid the market clearing price for synchronized reserves. All synchronized reserves are also assessed a penalty for nonperformance during the synchronized reserve events. Deployment of reserves during synchronized reserve events will be most efficient if the resources that are deployed and are subject to performance evaluation for their response are the resources that are committed as synchronized reserves. However, under PJM's planned Intelligent Reserve Deployment (IRD) approach, PJM will rely on units that do not have a reserve commitment, while unnecessarily holding back committed and compensated reserve units during a spin event.[118] This is because the IRD approach is just a SCED solution based on: load increased by a predetermined amount; inflexible Tier 2 reserves are converted to energy production; maintaining the reserve requirement. The result is that inflexible Tier 2 synchronized reserves are converted to energy production, while flexible Tier 2 and Tier 1 resources are held as reserves to meet the reserve requirement instead of responding to the spin event. Since PJM proposes penalties for lack of response during spin events for cleared and dispatched reserves, this results in inflexible Tier 2 resources potentially being subject to penalties disproportionately, while flexible Tier 2 and Tier 1 reserves may or may not be dispatched, and consequently may not be not subject to penalties. The IRD mechanism also creates a reliability risk since it relies on resources not committed as reserves to increase their output to recover ACE during a spin event, and these resources are not subject to a penalty for nonperformance.

While PJM recovers from a disturbance during a spinning event, PJM should also adjust the operating reserve demand curve (ORDC) for synchronized reserves to ensure that RT SCED does not have a competing objective of immediately replacing reserves that have been paid for, and are being used for their intended purpose. Without such an adjustment, RT SCED will have to depend on resources that are not deemed to be eligible for clearing as synchronized reserves to aid the recovery of ACE. Without such an adjustment, the prices will be artificially inflated, potentially triggering shortage pricing, during the times when reserves are used for their intended purpose. The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed.

Reserve Shortages in 2021

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the five minute target time RT SCED solutions indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO Reserve Zone and MAD Reserve Subzone), when multiple solutions indicated shortage of reserves, and how many of these resulted in shortage prices in LPC. For reliability reasons, and to maintain reserves to comply with NERC standards, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the minimum reserve requirement (MRR). To trigger shortage pricing, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement.

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[119] [120] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of

118 PJM. "Intelligent Reserve Deployment PJM Package," presented at the Synchronous Reserve Deployment Task Force, (July 1, 2021) at 3, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/task-forces/srdtf/2021/20210701/20210701-item-03-pjms-proposed-package-intelligent-reserve-deployment.ashx>.

119 A case is executed when it begins to solve. Most but not all cases are solved. RT SCED cases take about one to two minutes to solve.

120 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020. PJM dispatchers may solve additional cases at their discretion.

selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflects shortage pricing, and the rest of the solutions do not.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-84 shows, for each month of 2020 and 2021, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which more than one RT SCED solution showed a shortage of reserves, and the number of five minute pricing intervals for which the LPC solution showed a shortage of reserves. Prior to June 3, 2021, each execution of RT SCED produced three solutions, using three different levels of load bias. Beginning June 3, 2021, each execution of RT SCED produces five solutions, using five different levels of load bias. This resulted in an increase in RT SCED cases with reserve shortages in at least one of the solutions. Table 3-84 shows that, in 2021, 5,590 target times, or 5.3 percent of all five minute target times, had at least one RT SCED solution showing a shortage of reserves, and 1,572 target times, or 1.5 percent of all five minute target times, had more than one RT SCED solution showing a shortage of reserves. In 2020, there were 1,819 target times, or 1.7 percent of all five minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 592 target times, or 0.6 percent of all five minute target times, that had more than one RT SCED solution showing a shortage of reserves.

Table 3-84 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2020 through December 2021

Year, Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2020 Jan	8,928	172	1.9%	89	1.0%	0	0.0%
2020 Feb	8,352	94	1.1%	44	0.5%	0	0.0%
2020 Mar	8,916	173	1.9%	66	0.7%	0	0.0%
2020 Apr	8,640	208	2.4%	99	1.1%	2	1.0%
2020 May	8,928	113	1.3%	36	0.4%	0	0.0%
2020 Jun	8,640	114	1.3%	30	0.3%	0	0.0%
2020 Jul	8,928	110	1.2%	17	0.2%	0	0.0%
2020 Aug	8,928	95	1.1%	14	0.2%	0	0.0%
2020 Sep	8,640	64	0.7%	21	0.2%	0	0.0%
2020 Oct	8,928	327	3.7%	91	1.0%	3	0.9%
2020 Nov	8,652	181	2.1%	44	0.5%	3	1.7%
2020 Dec	8,928	168	1.9%	41	0.5%	1	0.6%
2020 Total	105,408	1,819	1.7%	592	0.6%	9	0.5%
2021 Jan	8,928	114	1.3%	22	0.2%	0	0.0%
2021 Feb	8,064	108	1.3%	28	0.3%	0	0.0%
2021 Mar	8,916	198	2.2%	46	0.5%	4	2.0%
2021 Apr	8,640	130	1.5%	24	0.3%	0	0.0%
2021 May	8,928	235	2.6%	48	0.5%	5	2.1%
2021 Jun	8,640	516	6.0%	165	1.9%	1	0.2%
2021Jul	8,928	460	5.2%	104	1.2%	0	0.0%
2021 Aug	8,928	429	4.8%	131	1.5%	7	1.6%
2021 Sep	8,640	545	6.3%	169	2.0%	2	0.4%
2021 Oct	8,928	730	8.2%	232	2.6%	2	0.3%
2021 Nov	8,652	1,320	15.3%	405	4.7%	4	0.3%
2021 Dec	8,928	805	9.0%	198	2.2%	3	0.4%
2021 Total	105,120	5,590	5.3%	1,572	1.5%	28	0.5%

In 2021, there were 28 five minute intervals with shortage pricing, while there were 1,572 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In 2020, there were nine five minute intervals with shortage pricing, while 592 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. Clear criteria for approval of shortage cases are needed.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions or implement shortage pricing when there are no shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases that are used to send dispatch signals to resources, and for pricing, to minimize discretion. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient.

Shortage Pricing Intervals in LPC

There were 28 five minute intervals with shortage pricing in 2021, compared to nine intervals in 2020, in PJM. PJM implemented fast start pricing on September 1, 2021. This could result in differences in reserve shortages in the dispatch run and the pricing run. From September 1 through December 31, 2021, there were 11 five minute intervals with shortage pricing, and there were no differences in the shortage pricing results in the dispatch and pricing run during these 11 intervals. Table 3-85 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the 17 intervals with shortage pricing due to synchronized reserve shortage from January through August 2021. Table 3-86 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the 11 intervals with shortage pricing in the dispatch and pricing runs due to synchronized reserve shortage from September through December, 2021. Table 3-87 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the 17 intervals with shortage pricing due to synchronized reserve shortage from January through August 2021. Table 3-88 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the 11 intervals with shortage pricing in the dispatch and pricing runs due to synchronized reserve shortage from September through December 2021. Table 3-89 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the four intervals with shortage pricing due to primary reserve shortage from January through August, 2021. Table 3-90 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the two intervals with shortage pricing in the dispatch and pricing runs due to primary reserve shortage from September through December, 2021. Table 3-91 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the three intervals with shortage pricing due to primary reserve shortage from January through August, 2021. Table 3-92 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the two intervals with shortage pricing in the dispatch and pricing runs due to primary reserve shortage from September through December, 2021.

PJM enforces an RTO wide reserve requirement and a supplemental reserve requirement for the MAD region. The MAD Reserve Subzone is nested within the RTO Reserve Zone. Resources located in the MAD Reserve Subzone can simultaneously satisfy the synchronized reserve requirement of the RTO Reserve Zone and the synchronized reserve requirement of the MAD Reserve Subzone. Resources located outside the MAD Reserve Subzone can satisfy the synchronized reserve requirement of the RTO Reserve Zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO Reserve Zone is set by the shadow price of the binding reserve requirement constraint of the RTO Reserve Zone.[121] The synchronized reserve clearing price of the MAD Reserve Subzone, nested within the RTO Reserve Zone, is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO Reserve Zone and the shadow price of the binding reserve requirement constraint of the MAD Reserve Subzone.

In all 28 intervals in 2021 with shortage pricing, both the RTO Zone and the MAD Subzone cleared with synchronized reserves less than their extended requirement. In six out of the 28 intervals, the synchronized reserves in the RTO Zone were short of the minimum reserve requirement, resulting in an $850 per MWh penalty factor. In 22 out of the 28 intervals, the synchronized reserves in the RTO Zone were greater than or equal to the minimum reserve requirement but short of the extended reserve requirement (minimum reserve requirement plus 190 MW), resulting in a penalty factor that is between $300 per MWh and $850 per MWh. The clearing price for synchronized reserves in the RTO Zone is the sum of the shadow prices of the synchronized reserve constraint for the RTO Zone and the primary reserve constraint for the RTO Zone. The clearing price for synchronized reserves in the MAD Subzone is the sum of the shadow prices of the synchronized reserve constraints for the RTO Zone and MAD Subzone and the shadow prices of the primary reserve constraints in the RTO and MAD Subzone.

Table 3-85 Real-time RTO synchronized reserve shortage intervals: January through August, 2021

Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)
02-Mar-21 06:30	1,835.0	1,305.6	529.4	$2,632.9	$1,700.0
17-Mar-21 10:10	1,859.0	1,452.1	406.9	$1,150.0	$1,150.0
22-Mar-21 19:45	1,786.0	1,256.5	529.5	$1,700.0	$1,700.0
22-Mar-21 19:50	1,783.0	1,422.9	360.1	$1,150.0	$1,150.0
07-May-21 06:30	1,812.0	1,786.5	25.5	$300.0	$300.0
19-May-21 17:10	1,832.0	1,812.8	19.2	$368.1	$368.1
19-May-21 17:15	1,829.0	1,672.4	156.6	$398.4	$398.4
26-May-21 10:25	1,817.0	1,682.5	134.5	$300.0	$300.0
26-May-21 10:30	1,817.0	1,682.5	134.5	$300.0	$300.0
02-Jun-21 17:00	1,826.0	1,691.3	134.7	$300.0	$300.0
20-Aug-21 16:15	1,773.0	1,583.0	190.0	$850.0	$850.0
20-Aug-21 16:20	1,773.0	1,583.0	190.0	$850.0	$850.0
20-Aug-21 18:00	1,780.0	1,598.5	181.5	$416.2	$416.2
23-Aug-21 16:50	1,780.0	1,666.2	113.8	$300.0	$300.0
23-Aug-21 16:55	1,776.0	1,670.4	105.6	$300.0	$300.0
23-Aug-21 17:00	1,777.0	1,653.5	123.5	$300.0	$300.0
23-Aug-21 17:05	1,777.0	1,653.5	123.5	$300.0	$300.0

Table 3-86 Real-time RTO synchronized reserve shortage intervals: September through December, 2021[122]

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)
27-Sep-21 17:00	1,816.0	1,695.4	120.6	$600.0	$600.0	1,816.0	1,695.4	120.6	$600.0	$600.0
27-Sep-21 17:05	1,816.0	1,695.4	120.6	$600.0	$600.0	1,816.0	1,695.4	120.6	$600.0	$600.0
28-Oct-21 18:35	1,731.0	1,656.6	74.4	$310.2	$310.2	1,731.0	1,656.6	74.4	$310.2	$310.2
28-Oct-21 18:40	1,737.0	1,722.9	14.1	$311.0	$311.0	1,737.0	1,722.9	14.1	$311.0	$311.0
12-Nov-21 17:20	1,592.5	1,497.1	95.4	$300.0	$300.0	1,592.5	1,497.1	95.4	$300.0	$300.0
12-Nov-21 17:25	1,590.7	1,400.7	190.0	$345.5	$345.5	1,590.7	1,400.7	190.0	$345.5	$345.5
12-Nov-21 17:30	1,590.5	1,400.5	190.0	$518.3	$518.3	1,590.5	1,400.5	190.0	$518.3	$518.3
12-Nov-21 17:35	1,590.5	1,400.5	190.0	$518.3	$518.3	1,590.5	1,400.5	190.0	$518.3	$518.3
07-Dec-21 17:25	1,832.0	1,687.3	144.7	$333.1	$333.1	1,832.0	1,687.3	144.7	$333.1	$333.1
08-Dec-21 09:05	1,860.0	1,537.9	322.1	$850.0	$850.0	1,860.0	1,537.9	322.1	$850.0	$850.0
08-Dec-21 09:10	1,856.0	1,435.2	420.8	$1,668.6	$1,668.6	1,856.0	1,435.2	420.8	$1,668.6	$1,668.6

121 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.

122 Prior to September 1, 2021, there were no separate dispatch and pricing runs, and the single solution did not incorporate fast start pricing. Beginning September 1, 2021, the LMPs are the output from the pricing run that incorporates fast start pricing.

On December 8, 2021, during the interval beginning 0910 EPT, there was no primary reserve shortage in the RTO reserve zone and the MAD subzone. Table 3-86 shows that the RTO synchronized reserve MCP reached $1,668.6 per MWh even though the ORDC for synchronized reserves has a cap of $850 per MWh and the RTO primary reserve MCP was zero. The RTO synchronized reserve MCP of $1,668.6 per MWh is less than the tariff specified overall cap on synchronized reserves of $1,700 per MWh, and the RTO synchronized reserve MCP was not capped by PJM. However, the price was inconsistent with the RTO synchronized reserve ORDC that has a maximum price of $850 per MWh. Without a simultaneous primary reserve MCP that is greater than zero, the synchronized reserve MCP for the RTO zone should not exceed $850 per MWh. On December 8, 2021, at 0910 EPT, PJM's process of implementing shortage pricing for synchronized reserves was inconsistent with the tariff defined ORDC. In the MAD subzone, the uncapped MCP reached $2,518.6 per MWh, which is the sum of the RTO synchronized reserve constraint shadow price ($1668.6 per MWh) and the MAD synchronized reserve constraint shadow price ($850 per MWh). PJM capped the MAD synchronized reserve MCP at $1,700 per MWh, the tariff defined overall cap for synchronized reserves. With primary reserve MCPs at zero, the uncapped MCP for MAD synchronized reserve should not exceed $1,700 per MWh. The process of calculating reserve constraint shadow prices and implementing reserve price caps in PJM is not transparent. The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices.

Table 3-87 Real-time MAD synchronized reserve shortage intervals: January through August, 2021

Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)
02-Mar-21 06:30	1,835.0	1,557.5	277.5	$2,782.2	$1,700.0
17-Mar-21 10:10	1,859.0	1,452.1	406.9	$2,000.0	$1,700.0
22-Mar-21 19:45	1,786.0	1,256.5	529.5	$3,400.0	$1,700.0
22-Mar-21 19:50	1,783.0	1,422.9	360.1	$2,300.0	$1,700.0
07-May-21 06:30	1,812.0	1,786.5	25.5	$600.0	$600.0
19-May-21 17:10	1,832.0	1,812.8	19.2	$668.1	$668.1
19-May-21 17:15	1,829.0	1,672.4	156.6	$698.4	$698.4
26-May-21 10:25	1,817.0	1,682.5	134.5	$600.0	$600.0
26-May-21 10:30	1,817.0	1,682.5	134.5	$600.0	$600.0
02-Jun-21 17:00	1,826.0	1,691.3	134.7	$600.0	$600.0
20-Aug-21 16:15	1,773.0	1,583.0	190.0	$1,573.6	$1,573.6
20-Aug-21 16:20	1,773.0	1,583.0	190.0	$1,544.1	$1,544.1
20-Aug-21 18:00	1,780.0	1,598.5	181.5	$716.2	$716.2
23-Aug-21 16:50	1,780.0	1,666.2	113.8	$600.0	$600.0
23-Aug-21 16:55	1,776.0	1,670.4	105.6	$600.0	$600.0
23-Aug-21 17:00	1,777.0	1,653.5	123.5	$600.0	$600.0
23-Aug-21 17:05	1,777.0	1,653.5	123.5	$600.0	$600.0

Table 3-88 Real-time MAD synchronized reserve shortage intervals: September through December, 2021

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)
27-Sep-21 17:00	1,816.0	1,695.4	120.6	$1,200.0	$1,200.0	1,816.0	1,695.4	120.6	$1,200.0	$1,200.0
27-Sep-21 17:05	1,816.0	1,695.4	120.6	$1,200.0	$1,200.0	1,816.0	1,695.4	120.6	$1,200.0	$1,200.0
28-Oct-21 18:35	1,731.0	1,656.6	74.4	$610.2	$610.2	1,731.0	1,656.6	74.4	$610.2	$610.2
28-Oct-21 18:40	1,737.0	1,722.9	14.1	$611.0	$611.0	1,737.0	1,722.9	14.1	$611.0	$611.0
12-Nov-21 17:20	1,592.5	1,497.1	95.4	$600.0	$600.0	1,592.5	1,497.1	95.4	$600.0	$600.0
12-Nov-21 17:25	1,590.7	1,400.7	190.0	$645.5	$645.5	1,590.7	1,400.7	190.0	$645.5	$645.5
12-Nov-21 17:30	1,590.5	1,400.5	190.0	$818.3	$818.3	1,590.5	1,400.5	190.0	$818.3	$818.3
12-Nov-21 17:35	1,590.5	1,400.5	190.0	$818.3	$818.3	1,590.5	1,400.5	190.0	$818.3	$818.3
07-Dec-21 17:25	1,832.0	1,687.3	144.7	$633.1	$633.1	1,832.0	1,687.3	144.7	$633.1	$633.1
08-Dec-21 09:05	1,860.0	1,537.9	322.1	$1,700.0	$1,700.0	1,860.0	1,537.9	322.1	$1,700.0	$1,700.0
08-Dec-21 09:10	1,856.0	1,435.2	420.8	$2,518.6	$1,700.0	1,856.0	1,435.2	420.8	$2,518.6	$1,700.0

Table 3-89 Real-time RTO primary reserve shortage intervals: January through August, 2021

Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)
02-Mar-21 06:30	2,657.5	2,405.6	251.9	$850.0	$850.0
17-Mar-21 10:10	2,693.5	2,536.1	157.4	$300.0	$300.0
22-Mar-21 19:45	2,584.0	2,357.7	226.3	$850.0	$850.0
22-Mar-21 19:50	2,579.5	2,406.9	172.6	$300.0	$300.0

Table 3-90 Real-time RTO primary reserve shortage intervals: September through December, 2021

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)
27-Sep-21 17:00	2,629.0	2,530.9	98.1	$300.0	$300.0	2,629.0	2,530.9	98.1	$300.0	$300.0
27-Sep-21 17:05	2,629.0	2,530.9	98.1	$300.0	$300.0	2,629.0	2,530.9	98.1	$300.0	$300.0

Table 3-91 Real-time MAD primary reserve shortage intervals: January through August, 2021

Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)
17-Mar-21 10:10	2,693.5	2,536.1	157.4	$300.0	$300.0
22-Mar-21 19:45	2,584.0	2,357.7	226.3	$1,700.0	$850.0
22-Mar-21 19:50	2,579.5	2,406.9	172.6	$600.0	$600.0

Table 3-92 Real-time MAD primary reserve shortage intervals: September through December, 2021

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)
27-Sep-21 17:00	2,629.0	2,530.9	98.1	$600.0	$600.0	2,629.0	2,530.9	98.1	$600.0	$600.0
27-Sep-21 17:05	2,629.0	2,530.9	98.1	$600.0	$600.0	2,629.0	2,530.9	98.1	$600.0	$600.0

On March 17, 2021, for the interval beginning 1010 EPT, both the RTO and MAD primary reserves were short of the extended requirements by 157.4 MW. The penalty factor for each reserve constraint violation was $300 per MWh. On March 22, 2021, for the interval beginning 1945 EPT, both the RTO and MAD primary reserves were short of the extended requirements by 226.3 MW. The penalty factor for each reserve constraint violation was $850 per MWh. Generally, the market clearing price (MCP) for primary reserves in the MAD Subzone will equal the sum of the penalty factor for the reserve requirement constraint of the RTO Reserve Zone and the penalty factor for the reserve requirement constraint of the MAD Reserve Subzone. Using this logic, the MCPs for primary reserves in the MAD Subzone should have been $600 per MWh on March 17, 2021, at 1010 EPT, and $1,700 per MWh on March 22, 2021, at 1945 EPT. However, the MCPs for primary reserves for the MAD Subzone were $300 per MWh and $850 per MWh. This occurred for different reasons in each of these intervals.

On March 17, 2021, at 1010 EPT, the MAD primary reserve requirement constraint was relaxed, resulting in the shadow price for the MAD primary reserve constraint equal to $0 per MWh. This is a result of the application of PJM's System Marginal Price (SMP) capping logic. Table 3-93 shows that PJM's SMP capping logic also resulted in relaxing the MAD synchronized reserve constraint on March 2, 2021 at 0630 EPT.

On March 22, 2021, at 1945 EPT, the MCP for primary reserves for the MAD subzone was capped at $850 consistent with the tariff cap on MCP for primary reserves and not due to the application of PJM's SMP capping logic.[123] The PJM tariff caps the MCP for primary reserves at one times the nonsynchronized reserve penalty factor for each zone or subzone, and caps the MCP for synchronized reserves at the sum of the penalty factor for synchronized reserve and the penalty factor for nonsynchronized reserve, but the PJM tariff does not specify a cap on the system marginal price.[124]

System Marginal Price Cap

In the PJM real time market, the SMP is capped at $3,750 per MWh. This cap is the result of the Energy Offer Cap ($2,000 per MWh under defined conditions), the Synchronous Reserve Penalty Factor from the first step on the demand curve ($850 per MWh), the Primary Reserve Penalty Factor from the first step on the demand curve ($850 per MWh) and a threshold ($50 per MWh). The Operating Agreement states that only two, of the four, reserve penalty factors may be applied.

If the SMP would otherwise exceed $3,750 per MWh, PJM solves the SCED optimization by progressively relaxing reserve requirement constraints until the SMP falls below the cap. For instance, if the original SMP is above $3,750, PJM would solve the SCED optimization by disabling the subzone (MAD) primary reserve requirement constraint. If the SMP from the relaxed SCED optimization is still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints. If the relaxed SCED optimization is still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints and the RTO primary reserve constraint.

Since 2018, the SMP has been capped in 95 SCED solutions, of which four SCED solutions were approved and used in the LPC to set the five minute LMPs in the PJM real-time market.

Table 3-93 shows the shadow price, MCP and SMP for all reserve constraints for SCED cases that were solved using PJM's SMP capping logic and set the prices in the PJM real-time market. The shadow price of a reserve requirement constraint is the marginal cost of satisfying an increase in the reserve requirement. The shadow price equals the penalty factor of the reserve requirement constraint if the total cleared reserves are below the requirement.

Table 3-94 shows the components of SMP for the five minute intervals that used SMP capping logic since 2018. The SMP is the marginal cost of satisfying an increase in load at the load weighted reference bus. That marginal cost includes the marginal cost of generation, the marginal cost of congestion and the marginal cost of reserves. By definition, all of these marginal costs are included in the marginal energy component of LMP at the load weighted reference bus, which is referred to as the system marginal price (SMP). The marginal cost of generation is the incremental offer price of the marginal generation resource adjusted for the marginal cost of losses. The marginal cost of congestion reflects the marginal cost of the unit required to meet the load if there are transmission constraints, including transmission penalty factors when relevant. If the marginal unit is also providing reserves, the marginal cost of reserves reflects the marginal cost incurred to meet the reserve requirement.

The SMP for the five minute interval beginning at 10:10 on March 17, 2021 was $3,653.98 per MWh. The MAD primary reserve constraint was disabled for this interval. Of the $3,653.98 per MWh, the marginal unit's incremental energy cost after accounting for the marginal cost of losses was $17.85 per MWh, the congestion cost was $1,546.98 per MWh and the reserve opportunity cost was $2,086.15 per MWh. The remaining $3.00 is rounding error.[125] The SMP, without the use of the capping logic, would have been at least $3,965.08 per MWh.[126]

The contribution of the transmission penalty factor of a violated transmission constraint to the SMP depends on

123 The 2021 Quarterly State of the Market Reports for PJM; Section 3; Energy Market incorrectly identified the March 22, 2021 1945 EPT interval as being subject to SMP capping.
124 OA Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).
125 The final SMP does not precisely match the sum of components due to rounded network parameters such as distribution factors and loss penalty factors used for deriving the components of the SMP. This difference is shown as rounding error.
126 The original SMP shown in the table represents the lower bound of the uncapped SMP. PJM does not report the segment of the disabled reserve constraint. To derive the original SMP, the lowest priced segment that results in the SMP exceeding the cap was used.

the location of the marginal units relative to the location of the load weighted reference bus. If the marginal unit is located such that an incremental increase in the load at the load weighted reference bus results in increased flow on the violated transmission constraint, the SMP reflects the positive contribution of the transmission penalty factor. The marginal congestion component, $1,546.98, for the five minute interval beginning at 10:10 on March 17, 2021, includes the contribution of transmission constraint penalty factors of two violated transmission constraints.

Table 3-93 Five minute intervals based on approved SCED cases that used SMP capping logic: January 2018 through December 2021

Five Minute Interval	Five Minute Interval	Reserve Constraint	Disabled	Shadow Price ($/MWh)	MCP ($/MWh)	SMP ($/MWh)
01OCT2019:15:00:00	October 01, 2019 15:00:00	MAD Primary Reserve	No	$0.00	$300.00	$3,651.02
01OCT2019:15:00:00	October 01, 2019 15:00:00	MAD Synchronized Reserve	Yes	$0.00	$1,150.00	$3,651.02
01OCT2019:15:00:00	October 01, 2019 15:00:00	RTO Synchronized Reserve	No	$850.00	$1,150.00	$3,651.02
01OCT2019:15:00:00	October 01, 2019 15:00:00	RTO Primary Reserve	No	$300.00	$300.00	$3,651.02
13NOV2020:18:00:00	November 13, 2020 18:00:00	MAD Primary Reserve	Yes	$0.00	$850.00	$3,166.28
13NOV2020:18:00:00	November 13, 2020 18:00:00	MAD Synchronized Reserve	No	$850.00	$2,550.00	$3,166.28
13NOV2020:18:00:00	November 13, 2020 18:00:00	RTO Primary Reserve	No	$850.00	$850.00	$3,166.28
13NOV2020:18:00:00	November 13, 2020 18:00:00	RTO Synchronized Reserve	No	$850.00	$1,700.00	$3,166.28
02MAR2021:06:30:00	March 02, 2021 06:30:00	MAD Synchronized Reserve	Yes	$0.00	$2,782.22	$2,994.68
02MAR2021:06:30:00	March 02, 2021 06:30:00	MAD Primary Reserve	No	$149.36	$999.36	$2,994.68
02MAR2021:06:30:00	March 02, 2021 06:30:00	RTO Primary Reserve	No	$850.00	$850.00	$2,994.68
02MAR2021:06:30:00	March 02, 2021 06:30:00	RTO Synchronized Reserve	No	$1,782.86	$2,632.86	$2,994.68
17MAR2021:10:10:00	March 17, 2021 10:10:00	MAD Synchronized Reserve	No	$850.00	$2,000.00	$3,653.98
17MAR2021:10:10:00	March 17, 2021 10:10:00	RTO Primary Reserve	No	$300.00	$300.00	$3,653.98
17MAR2021:10:10:00	March 17, 2021 10:10:00	RTO Synchronized Reserve	No	$850.00	$1,150.00	$3,653.98
17MAR2021:10:10:00	March 17, 2021 10:10:00	MAD Primary Reserve	Yes	$0.00	$300.00	$3,653.98

Table 3-94 Components of SMP for five minute intervals based on approved SCED cases that used SMP capping logic: January 2018 through December 2021

		Components of Final SMP				
Five Minute Interval	Lower Bound of Original SMP	Final SMP	Marginal Cost of Generation	Marginal Cost of Congestion	Marginal Cost of Reserves	Rounding Error
October 01, 2019 15:00:00	$3,950.36	$3,651.02	$33.88	$2,436.47	$1,173.81	$6.87
November 13, 2020 18:00:00	$4,049.76	$3,166.28	$520.20	$0.00	$2,645.22	$0.86
March 02, 2021 06:30:00	$3,891.21	$2,994.68	$30.51	$181.10	$2,780.81	$2.26
March 17, 2021 10:10:00	$3,965.08	$3,653.98	$17.85	$1,546.98	$2,086.15	$3.00

The MMU recommends that PJM cease the practice of capping the system marginal price in the RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh.

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as tier 1 bias or operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[127] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these actions taken by generators and by

127 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that may result in generators underperforming their submitted ramp rates. Instead of addressing these complexities through generator modeling improvements, PJM relies on a nontransparent method of adjusting generator parameters, called Degree of Generator Performance (DGP).[128] [129] PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

PJM adjusts ramp rates using DGP, deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set the dispatch signal equal to actual resource output. These manual interventions are, at best, rough approximations of the capability of generators and result in an inaccurate measurement of reserves.

Competitive Assessment

Market Structure

Market Concentration

The Herfindahl-Hirschman Index (HHI) concentration ratio is the sum of the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the real-time energy output of generators adjusted with scheduled imports. Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is between 1000 and 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[130]

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in 2021, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market during 2021 was unconcentrated on average (Table 3-95).[131] The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the

128 *See* "PJM Manual 12: Balancing Operations," Rev. 43 (June 6, 2021) Attachment A, P78. "PJM Manual 11: Energy and Ancillary Services Market Operations," does not mention the use of DGP in the market clearing engine.

129 PJM published a whitepaper that defines DGP and describes its use, which can be accessed at <http://www.pjm.com/~/media/etools/oasis/system-information/generation-performance-monitor-and-degree-of-generator-performance-white-paper.ashx> (July 2, 2020).

130 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).

131 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the supplier that is responsible for offering the unit in the energy market.

aggregate market even when the HHI level does not indicate a highly concentrated market structure. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

Table 3-95 Real-time hourly aggregate energy market HHI: 2020 and 2021

By offering supplier	Hourly Market HHI (2020)	Hourly Market HHI (2021)
Average	790	742
Minimum	569	532
Maximum	1166	1115
Highest market share (One hour)	28%	27%
Average of the highest hourly market share	20%	19%
# Hours	8,784	8,760
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-96 includes HHI values by supply curve segment, including base, intermediate and peaking plants for 2020 and 2021. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.[132] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market.

Table 3-96 Real-time hourly energy market HHI by generation segment: 2020 and 2021

	2020			2021		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	667	834	1203	636	795	1148
Intermediate	743	1551	6815	561	1196	6166
Peak	651	5757	10000	662	5956	10000

Figure 3-53 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in 2021.[133]

Figure 3-53 Real-time ICAP distribution by fuel and segment: 2021[134]

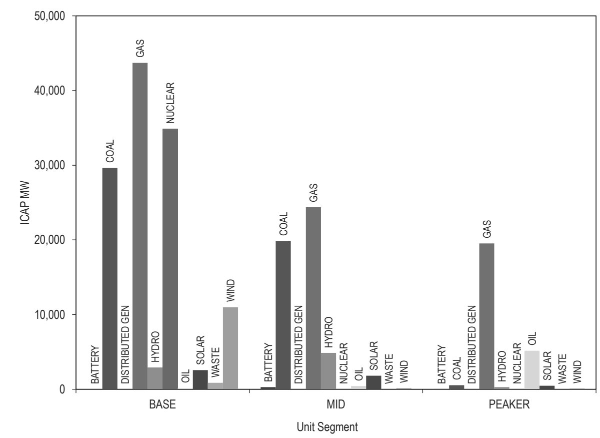


Figure 3-54 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from 2017 through 2021. Figure 3-54 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from 2017 through 2021, and the total ICAP of gas fired units in PJM classified as baseload generally increased from 2017 through 2021. In 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time. In 2021, the ICAP of coal fired units classified as baseload increased compared to 2020.

132 A unit is classified as base load if it runs for 50 percent of hours or more, as intermediate if it runs for less than 50 percent but greater than or equal to 10 percent of hours, and as peak if it runs for less than 10 percent of hours.

133 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their effective load carrying capability.

134 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012) <http://www.pjm.com/~/media/committees-groups/task-forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

Figure 3-54 Real-time annual gas and coal unit segment classification: 2017 through 2021

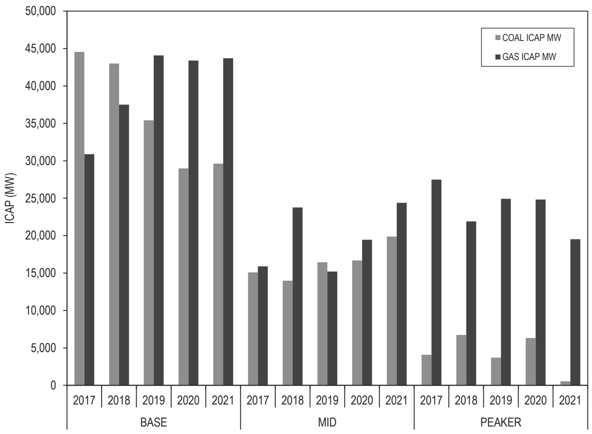
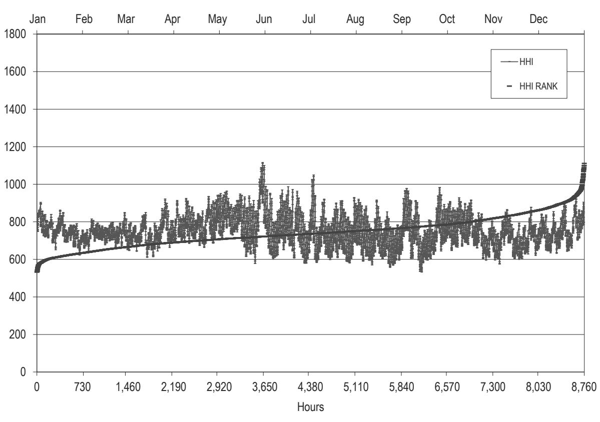


Figure 3-55 presents the hourly HHI values in chronological order and an HHI duration curve for 2021. The hours when the HHI increased above 1000 all occurred between May 29, 2021 through June 1, 2021, during the Memorial Day weekend and between July 3, 2021 through July 4, 2021, the Independence Day weekend.

Figure 3-55 Real-time hourly aggregate energy market HHI: 2021



Market Based Rates

Participation in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[135] FERC reviews the market based rate authority of PJM market sellers on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM region is included in the Northeast Region for purposes of the triennial review schedule. Triennial filings by utilities with market based rates authorizations must include a market power analysis or a statement that market power has been adequately mitigated under the PJM market rules. With Order No. 861, sellers may, in lieu of filing a market power analysis, rely on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[136]

The rules specify a separate a filing schedule for transmission owning utilities and nontransmission owning utilities. The rules define a study period for market power analyses including four complete seasons, not the calendar year. A study runs from December of one year through November of the following year (i.e., the period includes one complete winter season rather than splitting winter as a calendar year approach would).

The most recent triennial review filings for nontransmission owning utilities in PJM were due on June 20, 2020. The applicable study period for the June 20, 2020 triennial filing, ran from December 1, 2017, to November 30, 2018. Triennial review filings for transmission owners in PJM will be due in December 2022. The applicable study period for the December 2020 filing ran from December 1, 2020, to November 30, 2021.

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. The MMU has found that the capacity market is not competitive because the default

135 See *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 (2007), *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom.* Mont. Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011).

136 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019) ("Order No. 861").

Market Seller Offer Cap (MSOC) is inflated.[137] With these results and the supporting evidence, the MMU challenged the rebuttable presumption of sufficient market power mitigation for the June 2020 triennial review filings by generating unit owners in PJM and recommended that conditions limiting sellers to cost-based energy offers and a revised capacity market seller offer cap be required until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[138] In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.[139] [140]

Merger Reviews

FERC reviews contemplated dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[141]

FERC applies tests set forth in the 1996 Merger Policy Statement.[142] [143] The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates a Competitive Analysis Screen.[144]

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments including such analyses.[145] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[146] FERC has considered the MMU's analysis in reviewing mergers but continues to apply a definition of markets based on an outdated and static definition of relevant markets in PJM.[147]

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-97 shows transactions that involved entire resources that were completed in 2021, as reported to the Commission. Table 3-98 shows transactions that involved transfers of partial unit ownership that were completed in 2021, as reported to the Commission.[148]

137 See Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, (February 21, 2019), which can be accessed at <https://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf>.

138 See, e.g., Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 (August 28, 2020).

139 See 175 FERC ¶ 61,231 (2021).

140 See 174 FERC ¶ 61,212 (2021).

141 18 U.S.C. § 824b.

142 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).

143 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

144 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)

145 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

146 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

147 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

148 The transaction completion date is based on the notices of consummation submitted to the Commission.

Table 3-97 Completed transfers of entire resources: 2021

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
LES Landfill Units	LES Manager LLC	Energy Power Investment Company	June 10, 2021	EC21-61
Big Sky Wind	Blackrock Inc	Vitol	April 15, 2021	EC21-53
Mount Storm Wind	Castleton Commodities International	Clearway Energy Group LLC	April 23, 2021	EC21-52
PEI Power	Energy Transfer LP	Archaea Holdings, LLC	April 5, 2021	EC21-45
PEI Power	Archaea Holdings, LLC	Rice Acquisition Corp	September 15, 2021	EC21-84
Cypress Creek Renewables	Cypress Creek Holdings	EQT AB	October 8, 2021	EC21-108
Panda Stonewall (100%)	Panda Power Funds	Ares Management	November 9, 2021	EC21-99
Covanta	Covanta Holding Corporation	EQT AB	November 30, 2021	EC21-113

Table 3-98 Completed transfers of partial ownership of resources: 2021

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Competitive Power Ventures: Fairview (25%), Maryland (25%), Shore (37.5%)	Global Infrastructure Partners	OPC Energy	January 25, 2021	EC21-16
Yards Creek (50%)	JCPL	LS Power Development LLC	March 5, 2021	EC20-65
Hamilton Liberty, Hamilton Patriot (50%)	EIG Management	The Carlyle Group	June 9, 2021	EC21-54
Old Trail Wind Farm (49%)	OMERS Administration Corporation	Algonquin Power & Utilities Corp	June 16, 2021	EC21-78
Calvert Cliffs (49.99 %)	EDF, Inc	Exelon	August 6, 2021	EC20-72
Rev Renewables (Bath County, Yards Creek, Seneca) (10.7%)	LS Power	SK Inc	December 9, 2021	EC22-5

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[149] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of imposing short term asset divestiture requirements.

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not always correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[150] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of aggregate pivotal suppliers in the day-ahead energy market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the day-ahead energy market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is

149 See 138 FERC ¶ 61,167 at P 19 (2012) and *See In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 84698, Case No. 9271 (February 17, 2012) at 104–105 ("Order No. 84698").

150 One supplier, Exelon, is partially mitigated for aggregate market power through its merger agreement. The agreement is not part of the PJM market rules. See Monitoring Analytics, LLC, Letter attaching Settlement Terms and Conditions, FERC Docket No. EC11-83-000 and Maryland PSC Case No. 9271 (October 11, 2011).

not competing to meet the demand for energy. Generating units, import transactions, economic demand response, and INCs, are included for each supplier. Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-56 shows the number of days in 2020 and 2021 with one aggregate pivotal supplier, two aggregate jointly pivotal suppliers, and three aggregate jointly pivotal suppliers for the day-ahead energy market. One supplier was singly pivotal on the summer peak days in 2020 and multiple suppliers were singly pivotal on the summer peak days of 2021. One supplier was singly pivotal on February 15, 2021. Two suppliers were jointly pivotal on 128 days in 2020 and on 116 days in 2021. Three suppliers were jointly pivotal on 301 days in 2020 and on 286 days in 2021, despite average HHIs at persistently unconcentrated levels. In 2020 and 2021, the highest levels of aggregate market power occurred in the third quarter, PJM's summer peak load season. Outside the summer months, the frequency of pivotal suppliers increased on high demand days in January 2020 and in February 2021.

Figure 3-56 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

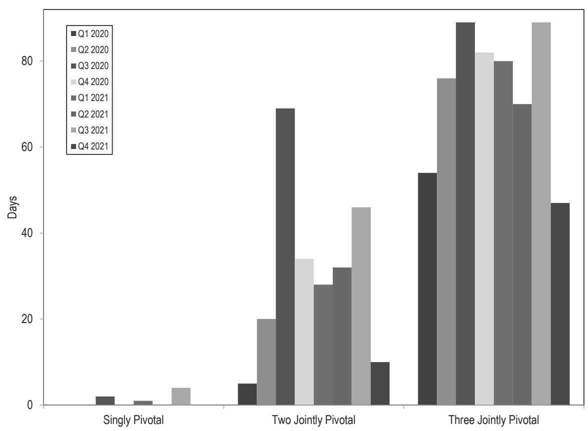


Table 3-99 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in 2021. The largest pivotal supplier was singly pivotal on four days in 2021. All of the top 10 suppliers were one of two pivotal suppliers on at least 16 days in 2021. All of the top 10 suppliers were one of three pivotal suppliers on at least 172 days in 2021.

Table 3-99 Day-ahead market pivotal supplier frequency: 2021

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	4	1.1%	108	29.6%	283	77.5%
2	3	0.8%	107	29.3%	281	77.0%
3	1	0.3%	61	16.7%	264	72.3%
4	0	0.0%	88	24.1%	286	78.4%
5	0	0.0%	61	16.7%	274	75.1%
6	0	0.0%	27	7.4%	234	64.1%
7	0	0.0%	23	6.3%	207	56.7%
8	0	0.0%	18	4.9%	201	55.1%
9	0	0.0%	18	4.9%	165	45.2%
10	0	0.0%	16	4.4%	172	47.1%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive. If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[151] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based, also called price-based, offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied when the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In 2021, the 500 kV system, 11 zones, and MISO experienced congestion resulting from one or more constraints binding for 100 or more hours, or resulting from a binding interface constraint (Table 3-100).[152] Table 3-100 shows that the 500 kV system, three zones and MISO experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from a binding interface constraint in every year from 2009 through 2021. Three control zones did not experience congestion resulting from one or more constraints binding for 100 or more hours or resulting from any binding interface constraint in any year from 2009 through 2021.[153]

151 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

152 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the control zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

153 The constraint data in the September through December, 2021 period is based on the dispatch run.

Table 3-100 Congestion hours resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2021

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
500 kV System	4,468	6,789	6,109	1,468	3,002	1,596	777	1,487	994	1,120	4,186	2,577	1,458
ACEC	149	172	234	0	208	0	394	439	0	500	108	0	0
AEP	1,045	1,636	2,510	0	2,611	2,710	1,274	796	469	1,878	808	1,361	1,018
APS	509	1,714	0	206	0	170	167	0	265	246	191	417	0
ATSI	157	0	0	208	270	489	242	1	165	1,686	1	0	0
BGE	152	470	1,041	2,970	1,760	6,255	9,601	11,434	2,178	3,135	812	9,491	1,660
COMED	1,212	2,080	1,134	4,554	5,143	4,119	5,878	7,336	2,257	1,148	457	1,074	812
DAY	0	0	0	0	0	0	0	0	0	0	0	0	181
DLCO	156	475	206	209	0	223	617	0	0	0	0	0	0
DOM	468	905	1,179	1,020	664	0	1,172	459	436	136	196	891	381
DPL	0	122	0	1,542	639	3,071	2,066	2,719	673	1,117	0	106	144
DUKE	0	0	0	109	0	0	112	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	0	0	0	0	400	0	0	0
EXT	0	0	0	0	0	0	0	0	788	0	0	0	0
JCPLC	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC	0	180	162	0	0	0	222	0	116	1,559	922	1,041	191
MISO	6,042	5,287	15,637	27,694	18,215	11,460	11,109	11,712	6,297	8,635	9,249	5,673	2,646
NYISO	0	0	0	0	167	143	834	2,130	332	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0
PE	103	284	0	0	176	4,281	1,683	451	3,074	1,648	2,065	2,999	309
PECO	247	0	788	386	732	1,953	895	832	1,961	1,474	1,404	306	480
PEPCO	149	1	0	143	245	41	0	0	0	0	0	0	0
PPL	176	118	40	350	452	148	266	936	2,044	436	1,124	891	1,042
PSEG	303	549	1,107	913	3,021	4,688	2,665	810	239	226	0	0	1,244
REC	0	0	0	0	0	0	0	0	0	0	0	0	0

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-101 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing the TPS test for the transfer interface constraints in the PJM Day-Ahead Energy Market.

Table 3-101 Day-ahead three pivotal supplier test details for interface constraints: 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005	Peak	108	512	29	29	0
	Off Peak	NA	NA	NA	NA	NA
AEP - DOM	Peak	332	542	21	7	14
	Off Peak	483	554	29	10	19
AP South	Peak	424	687	26	10	16
	Off Peak	222	342	21	8	12
BC Pepco	Peak	1,865	1,826	27	3	24
	Off Peak	725	1,108	14	0	14

Table 3-102 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing the TPS test for the 10 constraints that were binding for the most hours in the PJM Day-Ahead Energy Market. In the day-ahead energy market, the TPS test evaluates each constraint that was binding for each hour during the operating day.

Table 3-102 Day-ahead three pivotal supplier test details for top 10 congested constraints: 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Nottingham	Peak	252	354	24	11	13
	Off Peak	180	290	22	12	10
Berwick - Koonsville	Peak	3	12	3	0	2
	Off Peak	3	15	3	0	3
East Lima - Haviland	Peak	102	136	12	1	11
	Off Peak	107	140	11	1	11
Three Mile Island	Peak	317	228	19	2	17
	Off Peak	301	195	17	1	16
Gardners - Texas Eastern	Peak	76	13	3	0	3
	Off Peak	71	12	3	0	3
Northwest Tap - Purdue	Peak	84	98	12	0	11
	Off Peak	49	58	12	0	11
Graceton - Safe Harbor	Peak	292	229	21	2	18
	Off Peak	195	200	20	4	16
Ramapo (ConEd) - S Mahwah (RECO)	Peak	21	2	2	0	2
	Off Peak	NA	NA	NA	NA	NA
Brighton	Peak	676	1,036	35	22	14
	Off Peak	457	1,108	35	25	9
Cedar Grove Sub - William	Peak	209	156	8	0	8
	Off Peak	167	72	7	0	7

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the 2021.[154] While the real-time constraint hours include constraints that were binding in the five minute real-time dispatch solution (RT SCED), IT SCED, the software that performs the TPS test, may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times.[155] IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-103 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints in the PJM Real-Time Energy Market. Table 3-104 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-103 and Table 3-104 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

154 See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

155 Prior to September 1, 2021, the real-time binding constraints were identical in the dispatch (RT SCED) and pricing (LPC) solutions. Beginning September 1, 2021, with implementation of fast start pricing, the set of binding constraints can differ between RT SCED and LPC pricing solutions. The set of constraints reported here are based on the binding constraints in RT SCED. This is because PJM commits and mitigates units based on a dispatch solution in IT SCED without fast start pricing.

Table 3-103 Real-time three pivotal supplier test details for interface constraints: 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	328	421	19	5	14
	Off Peak	146	548	21	15	6
AEP - DOM	Peak	357	469	15	2	13
	Off Peak	333	445	17	2	15
AP South	Peak	330	722	20	11	10
	Off Peak	388	387	10	5	4
East	Peak	409	468	18	2	16
	Off Peak	NA	NA	NA	NA	NA
PA Central	Peak	15	169	6	2	4
	Off Peak	10	106	4	1	4

Table 3-104 Real-time three pivotal supplier test details for top 10 congested constraints: 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brighton	Peak	188	312	19	9	10
	Off Peak	140	250	17	8	9
Nottingham	Peak	86	170	12	6	6
	Off Peak	70	139	11	5	6
Northwest Tap - Purdue	Peak	79	98	6	0	6
	Off Peak	56	93	5	0	5
Lenox - North Meshoppen	Peak	10	25	3	0	3
	Off Peak	7	29	2	0	2
Prest - Tibb	Peak	33	45	2	0	2
	Off Peak	23	38	2	0	2
East Lima - Haviland	Peak	80	79	10	1	9
	Off Peak	71	99	10	2	8
Sandburg	Peak	72	105	10	2	8
	Off Peak	52	82	9	1	7
Three Mile Island	Peak	75	103	11	3	8
	Off Peak	48	73	9	3	6
Bagley - Raphael Road	Peak	25	12	2	0	2
	Off Peak	23	13	2	0	2
Cedar Grove Sub - William	Peak	27	31	1	0	1
	Off Peak	26	28	1	0	1

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[156] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-105 shows that 1.0 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-105 shows that 8.5 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

156 If a steam unit were to lower its cost-based offer in real time, it would become eligible for offer capping based on the online TPS test.

Table 3-105 Day-ahead units committed on price-based offers that cleared real-time: 2020 and 2021

	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
Year	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2020	11,847	2,580,561	184,592	0.5%	7.1%
2021	27,559	2,703,543	231,545	1.0%	8.5%

The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market.

Table 3-106 and Table 3-107 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping in the real-time energy market. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

Table 3-106 Summary of real-time three pivotal supplier tests applied for interface constraints: 2021

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005	Peak	223	223	100%	1	0%	0%
	Off Peak	30	30	100%	0	0%	0%
AEP - DOM	Peak	145	145	100%	4	3%	3%
	Off Peak	226	226	100%	6	3%	3%
AP South	Peak	113	113	100%	1	1%	1%
	Off Peak	58	34	59%	0	0%	0%
Eastern	Peak	48	48	100%	0	0%	0%
	Off Peak	0	0	NA	0	NA	NA
PA Central	Peak	589	471	80%	6	1%	1%
	Off Peak	447	304	68%	3	1%	1%

Table 3-107 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: 2021

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Brighton	Peak	22,258	22,246	100%	893	4%	4%
	Off Peak	24,195	24,188	100%	650	3%	3%
Nottingham	Peak	22,578	22,234	98%	239	1%	1%
	Off Peak	16,186	15,948	99%	259	2%	2%
Northwest Tap - Purdue	Peak	23,776	7,078	30%	13	0%	0%
	Off Peak	15,546	4,952	32%	3	0%	0%
Lenox - North Meshoppen	Peak	19,453	11,800	61%	11	0%	0%
	Off Peak	9,262	2,699	29%	3	0%	0%
Prest - Tibb	Peak	4,174	53	1%	0	0%	0%
	Off Peak	8,829	214	2%	0	0%	0%
East Lima - Haviland	Peak	11,333	143	1%	0	0%	0%
	Off Peak	15,683	474	3%	0	0%	0%
Sandburg	Peak	7,656	989	13%	1	0%	0%
	Off Peak	8,362	1,084	13%	8	0%	1%
Three Mile Island	Peak	19,415	18,248	94%	194	1%	1%
	Off Peak	4,272	4,051	95%	58	1%	1%
Bagley - Raphael Road	Peak	13,762	13,450	98%	76	1%	1%
	Off Peak	7,954	7,891	99%	38	0%	0%
Cedar Grove Sub - William	Peak	10,238	9,426	92%	84	1%	1%
	Off Peak	6,343	5,392	85%	55	1%	1%

Offer Capping for Local Market Power

In the PJM energy market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

There are some issues with the application of mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the day-ahead energy market and the real-time energy market.

In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. Only under the current approach, where operating parameters are tied to the cost parameters (startup cost, no load cost, and incremental energy offer), is this is consistent with the day-ahead energy market objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period. True least system production cost can be achieved using a approach in which operating parameters and offer parameters are independently evaluated. In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[157]

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-57 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

157 See OA Schedule 1 § 6.4.1(g).

Figure 3-57 Offers with varying markups at different MW output levels

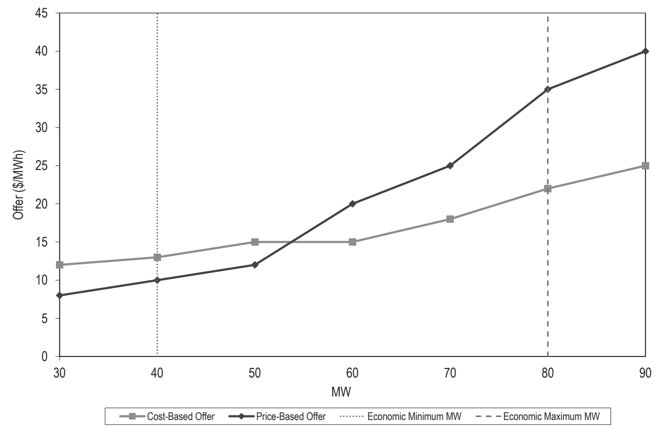


Table 3-108 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets in 2021. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, and they may elect to offer price-based offers, but are not required to do so.

Table 3-108 Units offered with crossing curves in the day-ahead and real-time energy markets: 2021

	Day-Ahead			Real-Time		
2021	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	61,326	838,152	7.3%	60,557	779,014	7.8%
Feb	56,100	750,072	7.5%	50,867	687,184	7.4%
Mar	70,110	844,732	8.3%	58,436	722,456	8.1%
Apr	73,785	805,512	9.2%	58,649	651,693	9.0%
May	91,452	842,592	10.9%	77,648	715,547	10.9%
Jun	103,578	822,216	12.6%	97,130	768,461	12.6%
Jul	104,730	852,936	12.3%	97,095	808,021	12.0%
Aug	110,185	853,728	12.9%	100,856	805,946	12.5%
Sep	106,904	825,960	12.9%	97,261	738,808	13.2%
Oct	98,115	850,944	11.5%	76,042	672,457	11.3%
Nov	82,830	817,520	10.1%	66,250	673,794	9.8%
Dec	83,050	859,368	9.7%	73,148	788,742	9.3%
Total	1,042,165	9,963,732	10.5%	913,939	8,812,123	10.4%

Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-109 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price based offer.

Table 3-109 Units offered with lower minimum run time on price compared to cost and with positive markup in the day-ahead and real-time energy markets: 2021

	Day-Ahead			Real-Time		
2021	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	13,151	838,152	1.6%	7,779	779,014	1.0%
Feb	12,162	750,072	1.6%	7,800	687,184	1.1%
Mar	11,513	844,732	1.4%	8,376	722,456	1.2%
Apr	8,220	805,512	1.0%	6,759	651,693	1.0%
May	6,489	842,592	0.8%	5,331	715,547	0.7%
Jun	6,367	822,216	0.8%	5,439	768,461	0.7%
Jul	6,631	852,936	0.8%	5,294	808,021	0.7%
Aug	6,229	853,728	0.7%	5,068	805,946	0.6%
Sep	8,062	825,960	1.0%	7,755	738,808	1.0%
Oct	8,528	850,944	1.0%	8,467	672,457	1.3%
Nov	4,795	817,520	0.6%	3,819	673,794	0.6%
Dec	5,562	859,368	0.6%	4,562	788,742	0.6%
Total	97,709	9,963,732	1.0%	76,449	8,812,123	0.9%

A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-58 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-58 Offers with a positive markup but different economic minimum MW

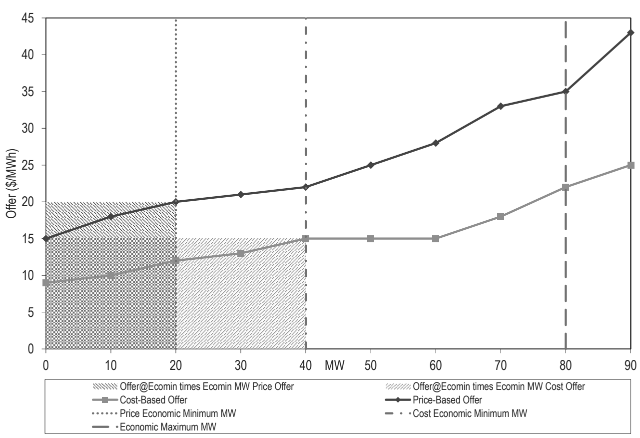


Table 3-110 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-110 Units offered with lower economic minimum MW on price compared to cost and with positive markup in the day-ahead and real-time energy markets: 2021

	Day-Ahead			Real-Time		
2021	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	0	838,152	0.0%	0	779,014	0.0%
Feb	216	750,072	0.0%	194	687,184	0.0%
Mar	1,486	844,732	0.2%	1,174	722,456	0.2%
Apr	1,440	805,512	0.2%	1,440	651,693	0.2%
May	1,488	842,592	0.2%	456	715,547	0.1%
Jun	1,440	822,216	0.2%	1,128	768,461	0.1%
Jul	744	852,936	0.1%	512	808,021	0.1%
Aug	864	853,728	0.1%	588	805,946	0.1%
Sep	1,152	825,960	0.1%	72	738,808	0.0%
Oct	1,488	850,944	0.2%	24	672,457	0.0%
Nov	817	817,520	0.1%	72	673,794	0.0%
Dec	359	859,368	0.0%	350	788,742	0.0%
Total	11,494	9,963,732	0.1%	6,010	8,812,123	0.1%

In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-59 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup. Table 3-111 shows the number and percent of dual fuel unit hours where the price-based offer does not have a comparable cost-based offer with a matching fuel, and contains a negative markup. The analysis includes only those units that offered multiple offers (cost or price) with different fuels in 2021.

Figure 3-59 Dual fuel unit offers

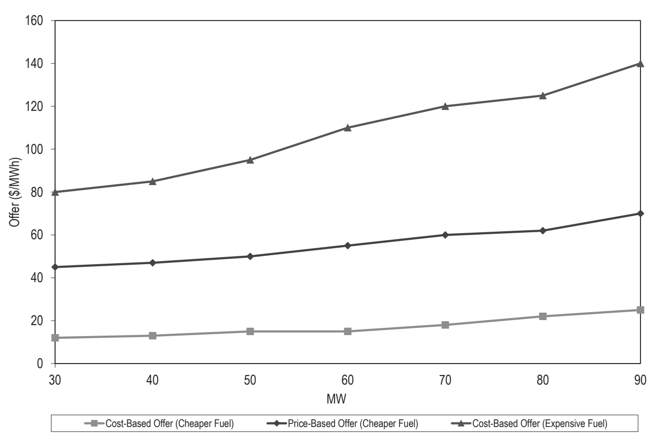


Table 3-111 Dual fuel unit offers with negative markup but different fuel: 2021

	Day-Ahead			Real-Time		
2021	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost
Jan	2,633	198,432	1.3%	2,633	178,118	1.5%
Feb	5,360	170,184	3.1%	5,360	145,413	3.7%
Mar	3,096	195,816	1.6%	3,096	150,583	2.1%
Apr	4,173	176,976	2.4%	4,173	152,556	2.7%
May	1,560	181,872	0.9%	1,560	159,862	1.0%
Jun	1,478	182,952	0.8%	1,478	177,296	0.8%
Jul	10,488	197,808	5.3%	10,488	190,135	5.5%
Aug	9,451	198,768	4.8%	9,451	188,851	5.0%
Sep	9,294	188,400	4.9%	9,294	171,114	5.4%
Oct	12,503	183,120	6.8%	12,503	152,438	8.2%
Nov	12,584	180,465	7.0%	12,584	152,575	8.2%
Dec	5,416	194,208	2.8%	5,416	178,788	3.0%
Total	78,036	2,249,001	3.5%	78,036	1,997,729	3.9%

These issues can be solved by simple rule changes.[158] The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. This means that the cost-based and price-based offer curves never cross.[159]

Levels of offer capping have historically been low in PJM, as shown in Table 3-113. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[160] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-112 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market excluding units that were committed for reliability reasons, providing black start and providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[161] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update. This is reflected in the slightly higher rate of offer capping in the real-time energy market since 2017.

Table 3-112 Offer capping statistics – energy only: 2017 to 2021

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.3%	0.2%	0.0%	0.0%
2018	0.9%	0.5%	0.1%	0.1%
2019	1.7%	1.3%	1.3%	0.9%
2020	1.0%	1.1%	1.6%	1.3%
2021	1.5%	1.2%	1.6%	1.0%

Table 3-113 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons. Reliability reasons include reactive support or local voltage support. PJM creates closed loop interfaces to, in some

158 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

159 See related recommendations about mitigation of operating parameters and financial offer parameters.

160 See OA Schedule 1 § 6.4.1.

161 Prior to the *2018 Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

cases, model reactive constraints. The result was higher LMPs in the closed loop interfaces, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support over time in Table 3-114. In instances where units are committed and offer capped for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief, and not for reliability. They are included in the offer capping percentages in Table 3-112. Prior to closed loop interfaces, these units were considered as committed for reactive support, and were included in the offer capping statistics for reliability in Table 3-114.

Table 3-113 Offer capping statistics for energy and reliability: 2017 to 2021

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.4%	0.4%	0.1%	0.2%
2018	1.0%	0.8%	0.2%	0.3%
2019	1.7%	1.3%	1.3%	0.9%
2020	1.0%	1.1%	1.6%	1.3%
2021	1.6%	1.3%	1.6%	1.0%

Table 3-114 shows the offer capping percentages for units committed for reliability reasons, including units committed for reactive support. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment. However, the price-based offers have inflexible parameters such as longer minimum run times that may lead to higher total commitment cost if the unit was only needed for a shorter period that is less than its inflexible minimum run time.

Table 3-114 Offer capping statistics for reliability: 2017 to 2021

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.10%	0.20%	0.10%	0.20%
2018	0.13%	0.29%	0.10%	0.21%
2019	0.01%	0.02%	0.00%	0.01%
2020	0.00%	0.01%	0.00%	0.00%
2021	0.03%	0.04%	0.02%	0.03%

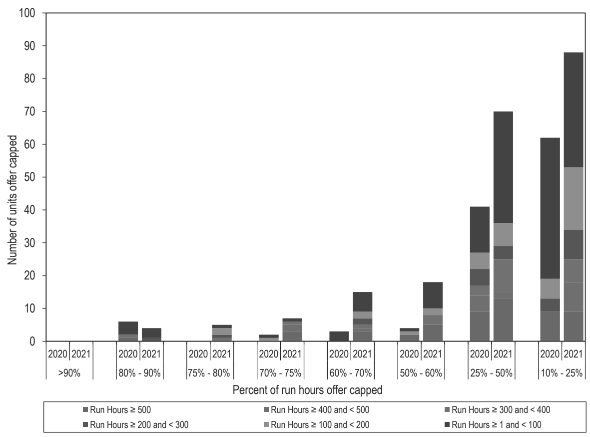
Table 3-115 presents data on the frequency with which units were offer capped in 2020 and 2021 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-115 shows that four units were offer capped for 80 percent or more of their run hours in 2021 compared to six units in 2020.

Table 3-115 Real-time offer capped unit statistics: 2020 and 2021

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Year	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
	2020	0	0	0	0	0	0
90%	2021	0	0	0	0	0	0
	2020	1	0	1	0	0	4
80% and < 90%	2021	0	0	0	1	0	3
	2020	0	0	0	0	0	0
75% and < 80%	2021	0	0	1	1	2	1
	2020	0	0	0	0	1	1
70% and < 75%	2021	3	2	1	0	0	1
	2020	0	0	0	0	0	3
60% and < 70%	2021	3	1	1	2	2	6
	2020	2	0	0	0	1	1
50% and < 60%	2021	5	0	3	0	2	8
	2020	9	5	3	5	5	14
25% and < 50%	2021	13	2	10	4	7	34
	2020	9	0	0	4	6	43
10% and < 25%	2021	9	9	7	9	19	35

Figure 3-60 shows the frequency with which units were offer capped in 2020 and 2021 for failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons.

Figure 3-60 Real-time offer capped unit statistics: 2020 and 2021



Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. When a seller responds competitively to a market price, markup is zero. When a seller exercises market power in its pricing, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[162] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-116 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-117 shows the average markup index of marginal units in the real-time energy market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[163] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

PJM implemented Fast Start Pricing on September 1, 2021. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer, and markup in the amortized no load offer.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. The PJM Market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[164]

In 2021, the average markup index in the real-time market was less than 0.01. The average dollar markups of units with offer prices less than $10 was negative

162 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

163 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

164 See PJM. "Manual 15: Cost Development Guidelines," Rev. 39 (Jan. 18, 2022).

(-$5.22 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was negative (-$0.23 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in 2021, 1.5 percent had offer prices above $150 per MWh. Among the units that were marginal in 2020, 0.3 percent had offer prices greater than $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2021 was more than $400, and the highest markup in 2020 was more than $400.

Table 3-116 Real-time average marginal unit markup index (By offer price category unadjusted): 2020 and 2021

	2020			2021		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.06)	($1.26)	15.0%	0.23	($5.22)	7.1%
$10 to $15	0.03	$0.15	36.4%	(0.07)	($1.37)	4.0%
$15 to $20	(0.01)	($0.46)	30.1%	(0.04)	($0.90)	17.3%
$20 to $25	0.02	($0.14)	11.7%	(0.03)	($0.86)	19.3%
$25 to $50	0.09	$2.51	5.1%	0.01	($0.21)	40.9%
$50 to $75	0.52	$30.46	0.4%	0.10	$4.98	8.0%
$75 to $100	0.53	$45.89	0.1%	0.23	$19.14	1.2%
$100 to $125	0.11	$12.95	0.5%	0.26	$27.67	0.5%
$125 to $150	0.02	$2.21	0.4%	0.33	$44.44	0.2%
$150 to $400	0.15	$25.29	0.3%	0.11	$23.03	1.5%
All Offers	0.01	$0.21	100.0%	0.01	$0.39	100.0%

Table 3-117 Real-time average marginal unit markup index (By offer price category adjusted): 2020 and 2021

	2020			2021		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.00	($0.65)	15.0%	0.24	($5.16)	7.1%
$10 to $15	0.11	$1.30	36.4%	(0.00)	($0.23)	4.0%
$15 to $20	0.08	$1.15	30.1%	0.04	$0.51	17.3%
$20 to $25	0.10	$1.87	11.7%	0.05	$0.99	19.3%
$25 to $50	0.17	$5.02	5.1%	0.08	$2.40	40.9%
$50 to $75	0.56	$32.99	0.4%	0.17	$9.30	8.0%
$75 to $100	0.58	$49.64	0.1%	0.30	$24.45	1.2%
$100 to $125	0.20	$22.09	0.5%	0.32	$34.30	0.5%
$125 to $150	0.11	$14.37	0.4%	0.38	$51.04	0.2%
$150 to $400	0.23	$37.58	0.3%	0.19	$38.68	1.5%
All Offers	0.09	$1.75	100.0%	0.08	$2.80	100.0%

Table 3-118 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[165] Table 3-119 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In 2021, using unadjusted cost-based offers for coal units, 46.93 percent of marginal coal units had negative markups. In 2021, using adjusted cost-based offers for coal units, 58.40 percent of marginal coal units had negative markups. The share of marginal gas units with negative markups at the dispatch point on their offer curve increased from 38.51 percent in 2020 to 46.55 percent in 2021 when using unadjusted cost based offers. Most marginal combined cycle units had significant negative markups, particularly during the periods of high natural gas prices in February 2021. Cost-based offers for gas fired units are frequently based on the current spot price of fuel while price-based offers may reflect a range of factors including sellers' fuel purchase prices and power sales prices.

165 Other fuel types were excluded based on data confidentiality rules.

Table 3-118 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): 2020 and 2021

	2020			2021		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	58.40%	21.72%	19.88%	46.93%	23.20%	29.87%
Gas	38.51%	6.07%	55.42%	46.55%	17.03%	36.42%
Oil	3.99%	95.55%	0.46%	4.43%	93.93%	1.64%

Table 3-119 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): 2020 and 2021

	2020			2021		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	34.75%	17.85%	47.40%	29.43%	13.46%	57.11%
Gas	24.66%	4.48%	70.86%	30.04%	8.40%	61.55%
Oil	2.13%	73.80%	24.07%	1.77%	93.28%	4.94%

Figure 3-61 shows the frequency distribution of hourly markups for all gas units offered in 2020 and 2021 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[166] Of the gas units offered in the PJM market in 2021, 19.8 percent of gas unit hours had a maximum markup that was negative and 12.6 percent of gas fired unit hours had a maximum markup above $100 per MWh. The share of offered gas units with maximum markup that was negative decreased in 2021 compared to 2020 while the share of marginal gas units with negative markups increased.

Figure 3-61 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: 2020 and 2021

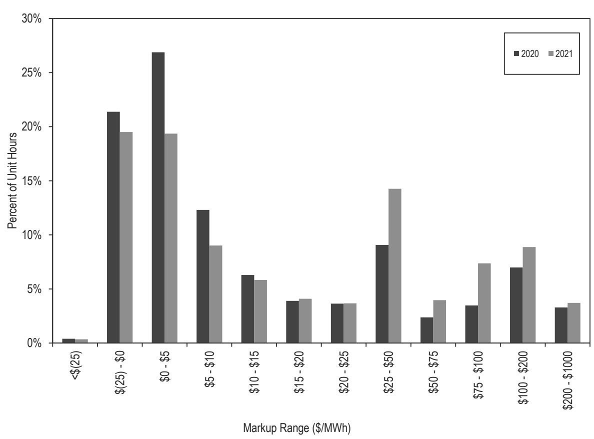


Figure 3-62 shows the frequency distribution of hourly markups for all coal units offered in 2020 and 2021 using unadjusted cost-based offers. Of the coal units offered in the PJM market in 2021, 32.8 percent of coal unit hours had a maximum markup that was negative or equal to zero, decreasing from 47.6 in 2020. The share of offered coal units with maximum markup that was negative and the share of marginal coal units with negative markups decreased in 2021 compared to 2020.

Figure 3-62 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: 2020 and 2021

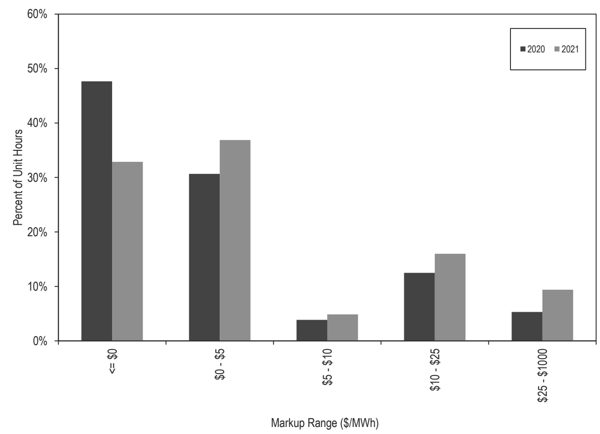
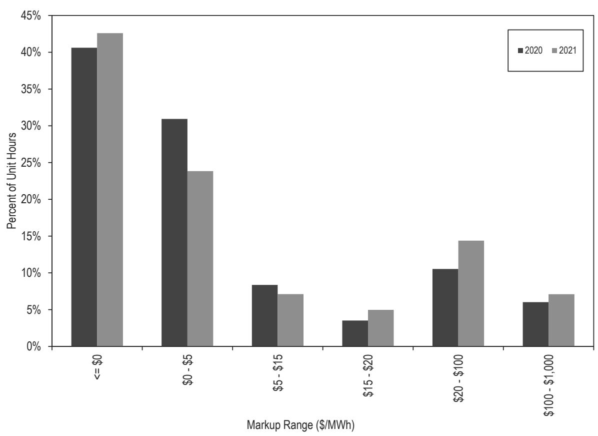


Figure 3-63 shows the frequency distribution of hourly markups for all offered oil units in 2020 and 2021 using unadjusted cost-based offers. Of the oil units offered in the PJM market in 2021, 42.5 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 7.0 percent of oil fired unit hours had a maximum markup above $100 per MWh.

166 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-63 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: 2020 and 2021

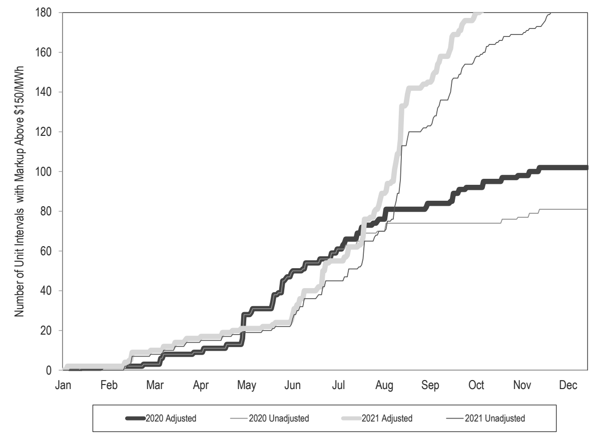


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Figure 3-64 shows the number of marginal unit intervals in 2021 and 2020 with markup above $150 per MWh. For several of the marginal unit intervals with markups above $150 per MWh, the units failed the TPS test for the hour. These exercises of market power are a result of PJM's failure to address the issues with the offer capping process identified by the MMU. If PJM adopted the MMU's recommendations, these exercises of market power would not occur.

Figure 3-64 Cumulative number of unit intervals with markups above $150 per MWh: 2020 and 2021



Day-Ahead Markup Index

Table 3-120 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. The average dollar markups of units with offer prices less than $10 was positive ($0.58 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was positive ($0.63 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in the day-ahead market in 2021, none had offer prices above $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in 2021 was more than $140 per MWh while the highest markup in 2020 was less than $80 per MWh.

Table 3-120 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2020 and 2021

	2020			2021		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.05)	($1.90)	1.7%	0.43	$0.58	1.5%
$10 to $15	0.08	$0.73	5.0%	0.10	$0.63	0.4%
$15 to $20	0.08	$0.97	6.2%	0.09	$1.26	2.8%
$20 to $25	0.02	($0.06)	2.4%	0.00	($0.30)	4.0%
$25 to $50	0.07	$2.04	1.1%	0.04	$0.73	8.7%
$50 to $75	0.18	$10.25	0.0%	0.15	$4.19	1.7%
$75 to $100	0.48	$42.31	0.0%	0.30	$24.62	0.2%
$100 to $125	0.00	($0.01)	0.0%	0.34	$35.20	0.1%
$125 to $150	0.00	$0.34	0.0%	0.15	$20.14	0.0%
>= $150	0.00	$0.69	0.0%	0.02	$3.18	0.2%
All Offers	0.06	$0.56	16.5%	0.07	$1.36	19.5%

Table 3-121 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers. In 2021, 2.8 percent of day-ahead marginal resources had offers between $15 and $20 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.02 in 2020, to 0.46 in 2021 in the offer price category less than $10.

Table 3-121 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2020 and 2021

	2020			2021		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.02	($1.38)	1.7%	0.46	$0.72	1.5%
$10 to $15	0.15	$1.84	5.0%	0.18	$1.82	0.4%
$15 to $20	0.15	$2.44	6.2%	0.17	$2.80	2.8%
$20 to $25	0.10	$1.94	2.4%	0.09	$1.78	4.0%
$25 to $50	0.15	$4.62	1.1%	0.12	$3.83	8.7%
$50 to $75	0.25	$14.60	0.0%	0.22	$9.12	1.7%
$75 to $100	0.51	$44.70	0.0%	0.36	$29.99	0.2%
$100 to $125	0.02	$2.34	0.0%	0.40	$42.14	0.1%
$125 to $150	0.02	$2.63	0.0%	0.20	$26.18	0.0%
>= $150	0.08	$12.98	0.0%	0.10	$19.76	0.2%
All Offers	0.14	$2.01	16.5%	0.15	$4.07	19.5%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly. Table 3-122 shows the caps on the three parts of cost-based and price-based offers.

Table 3-122 Cost-based and price-based offer caps

Offer Type	No Load and Start Cost Option	Incremental Offer Curve Cap	No Load Cost Cap	Start Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies		
Price-Based	Cost-Based	$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies
	Price-Based		No cap but can only be changed twice a year.	No cap but can only be changed twice a year.

Table 3-123 shows the number of units that chose the cost-based option and the price-based option. In 2021, 91 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, same as in 2020.

Table 3-123 Number of units selecting cost-based and price-based no load and start costs: 2020 and 2021

	2020		2021	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	534	91%	523	91%
Price-Based	51	9%	50	9%
Total	585	100%	573	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-124 shows the average markup in the no load and start costs in 2020 and 2021. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs. The price-based offers were actually lower than the cost-based offers. Generators that selected the price-based start and no load option offered on average with a negative markup on the no load cost but with very large positive markups on the start costs.

Table 3-124 No load and start cost markup: 2020 and 2021

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2020	Cost-Based	(9%)	(6%)	(6%)	(6%)
	Price-Based	(2%)	568%	710%	772%
2021	Cost-Based	(7%)	(8%)	(9%)	(9%)
	Price-Based	(48%)	281%	309%	377%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In 2021, 7.0 percent of the marginal units set prices based on cost-based offers, 0.1 percentage points lower than in 2020.

The efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer in the PJM market rules is not correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers. FERC's decision to permit maintenance costs in cost-based offers that are not short run marginal costs also results in overstated cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are directly related to energy production. The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and, in addition, allows for multiple interpretations, which could lead to tariff violations. The incorrect rules will lead to higher energy market prices and higher uplift.

There are three types of costs identified under PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer, a variable cost, is that the cost is "directly related to electric production."[167]

Variable costs are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.[168]

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

The MMU recommends that PJM require that the level of costs includable in cost-based offers not exceed the unit's short run marginal cost.

Fuel Cost Policies

Fuel cost policies (FCP) document the process by which market sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel Cost Policy Review

Table 3-125 shows the status of all fuel cost policies (FCP). As of December 31, 2021, 741 units (87 percent) had an FCP passed by the MMU and 108 units (13 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 22,377 MW. All units' FCPs were approved by PJM. As of December 31, 2021, 474 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.[169]

Table 3-125 FCP Status for PJM generating units: December 31, 2021

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	741	0	108	849
Total	741	0	108	849

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM approved every FCP failed by the MMU.

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic,

167 See 167 FERC ¶ 61,030 (2019).
168 See OA Schedule 2 § 1.1(a).
169 See OA Schedule 2 § 2.1.

accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic.[170] Verifiable means that the FCP requires a market seller to provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[171] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's standard effectively requires algorithmic fuel cost policies by describing the requirements.[172] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[173]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some fuel cost policies did not meet are:[174] accuracy (reflect applicable costs accurately); and fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in dollars per MWh or in dollars per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar units.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were the use of unverifiable fuel costs and the use of available market information that results in inaccurate expected costs.

Some of the failed fuel cost polices include unverifiable cost estimates. Some policies include options under which the estimate of the natural gas commodity cost can be calculated by the market seller without specifying a verifiable, systematic method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.

Some of the failed fuel cost polices include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is generally not a market clearing price and is not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

170 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) at P 11 ("October 7th Filing").
171 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
172 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
173 September 16th Filing at P 8.
174 See PJM Operating Agreement Schedule 2 § 2.3 (a).

Cost-Based Offer Penalties

Market Sellers are assessed penalties when they submit cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[175] Penalties are assessed when both PJM and the MMU are in agreement.

In 2021, 129 penalty cases were identified, 104 resulted in assessed cost-based offer penalties, five resulted in disagreement between the MMU and PJM, and 20 remain pending PJM's determination. The five disagreements in 2021 between the MMU and PJM are related to the calculation of fuel costs during pipeline constrained situations. In 2021, 27 penalty cases were self identified by market sellers. These cases were for 124 units owned by 21 different companies. Table 3-127 shows the penalties by the year in which participants were notified.

Table 3-126 Cost-based offer penalty cases by year notified: May 2017 through December 2021

Year notified	Cases	Assessed penalties	Self Identified	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	0	1	0	55	16
2018	187	161	0	26	0	138	35
2019	57	57	0	0	0	57	19
2020	142	136	24	5	1	124	25
2021	129	104	27	5	20	124	21
Total	572	514	51	37	21	387	58

Since 2017, 572 penalty cases have been identified, 514 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM, 21 remain pending PJM's determination and 51 were self identified by market sellers. The 514 cases were from 387 units owned by 58 different companies. The total penalties were $3.8 million, charged to units that totaled 111,827 available MW. The average penalty was $1.47 per available MW. This means that a 100 MW unit would have paid a penalty of $3,538.[176] Table 3-127 shows the total cost-based offer penalties since 2017 by year.

Table 3-127 Cost-based offer penalties by year: May 2017 through December 2021

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	21	$556,826	16,930	$1.56
2018	127	34	$1,265,698	26,343	$2.27
2019	79	21	$490,926	19,798	$1.10
2020	139	26	$412,859	22,467	$0.84
2021	111	21	$908,964	26,289	$1.48
Total	548	61	$3,635,272	111,827	$1.47

The incorrect cost-based offers resulted from incorrect application of fuel cost policies, lack of approved fuel cost policies, fuel cost policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

2020 Fuel Cost Policy Changes

On July 28, 2020, the Commission approved tariff revisions that modified the fuel cost policy process and the cost-based offer penalties.[177]

The tariff revisions replaced the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates. Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).

The tariff revisions removed the requirement for units with zero marginal cost to have an approved fuel cost policy but also included a zero offer cap for cost-based offers for units that do not have an approved fuel cost policy.

The tariff revisions allow a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens

175 See OA Schedule 2 § 6.

176 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

177 172 FERC ¶ 61,094 (2020).

market power mitigation by allowing market sellers to make offers without an approved fuel cost policy. The proposed approach allows the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

The tariff revisions replace the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.

The tariff revisions reduce the penalties for noncompliant cost-based offers in two situations. When market sellers report their noncompliant cost-based offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The tariff revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This new provision allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so.

The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers.

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[178] The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.[179] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[180] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average

178 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
179 167 FERC ¶ 61,030 (2019).
180 168 FERC ¶ 61,134 (2019).

economic maximum and average minimum run time of the units in 2021.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels for 2021 was two percent higher than the approved variable operating and maintenance cost approved by PJM in 2020.[181]

The average variable operating and maintenance cost approved by PJM for combined cycles for 2021 was two percent higher than the approved variable operating and maintenance cost approved by PJM in 2020.

The average variable operating and maintenance cost approved by PJM for coal units for 2020 was three percent higher than the approved variable operating and maintenance cost approved by PJM in 2020.

Table 3-128 shows the amount of capacity offered within several ranges of VOM costs. Table 3-128 shows that 772 MW have an approved effective VOM above $100 per MWh and 2,324 MW have an approved effective VOM between $50 and $100 per MWh.

Table 3-128 Approved Effective VOM Costs in dollars per MWh: 2019 through 2021

	Offered MW		
Approved VOM Range ($/MWh)	2019	2020	2021
$0 to $5 per MWh	69,025	71,898	64,131
$5 to $10 per MWh	37,325	30,325	34,369
$10 to $20 per MWh	14,276	15,931	21,492
$20 to $50 per MWh	5,402	4,938	5,015
$50 to $100 per MWh	2,302	3,146	2,324
Above $100 per MWh	1,159	1,044	772

High VOM levels allow generators to economically withhold energy and to exercise market power even when offers are capped at the cost-based offer to mitigate market power. The MMU recommendation to limit cost-based offers to short run marginal costs would prevent such withholding. When units are not committed due to high VOM costs and instead a unit with higher short run marginal costs is committed, the market outcome is inefficient. When units that fail the TPS test are committed on their price-based offer when their short run marginal cost is lower, the market outcome is inefficient.

MMU analysis shows that as CTs, CCs and coal units run for more hours, the VOM cost approved by PJM decreases. This is an indication that fixed costs are included in VOM costs. Fuel costs per MWh remain constant or increase as run hours and the heat rate increase. Fixed costs should not be includable in cost-based energy offers.

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data and PJM's review is dependent on the level of detail provided by the market seller. Recent changes in PJM's review process, triggered by MMU questions, required more details from market sellers and have led to the appropriate exclusion of expenses that were previously included.[182]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market

181 PJM reviews VOM once per year. The results reflect PJM's most recent review.

182 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>.

participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[183]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15.

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the unit is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

183 The peak adder is equal to $300 times three divided by 5 MW.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Frequently Mitigated Units (FMU) and Associated Units (AU)

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[184] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder in January.

Table 3-129 shows, by month, the number of FMUs and AUs from January 2020 through December 2021. For example, in September 2020, there was one FMU and AU in Tier 1, zero FMUs and AUs in Tier 2, and two FMUs and AUs in Tier 3.

Table 3-129 Number of frequently mitigated units and associated units (By month): January 2020 through December 2021

	2020				2021			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	0	0	0	0	1	0	1
February	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	2	0	0	2	0	0	0	0
July	2	0	0	2	0	0	0	0
August	1	0	0	1	0	0	0	0
September	1	0	2	3	0	0	0	0
October	2	0	2	4	0	0	0	0
November	2	1	2	5	0	0	0	0
December	2	1	2	5	0	0	0	0

Effective in the 2020/2021 planning year, default Avoidable Cost Rates are no longer defined in the tariff. If a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) are greater than zero, and if the generating unit does not have an approved unit specific Avoidable Cost Rate, the generating unit does not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

Market Performance

Ownership of Marginal Resources

Table 3-130 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[185] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2021, and summed by the parent company that offers the marginal resource into the real-time energy market. In 2021, the offers of one company resulted in 13.0 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 44.2 percent of the real-time load-weighted average PJM system LMP. In 2021, the offers of one company resulted in 16.2 percent of the peak hour real-time load-weighted PJM system LMP.

184 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 State of the Market Report for PJM*, Volume II, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

185 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-130 Marginal unit contribution to real-time load-weighted LMP (By parent company): 2020 and 2021

2020						2021					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	16.4%	16.4%	1	16.2%	16.2%	1	13.0%	13.0%	1	16.2%	16.2%
2	11.0%	27.4%	2	13.0%	29.2%	2	12.3%	25.2%	2	10.9%	27.1%
3	10.7%	38.1%	3	9.9%	39.1%	3	10.3%	35.5%	3	10.3%	37.4%
4	6.3%	44.4%	4	6.1%	45.2%	4	9.0%	44.5%	4	8.2%	45.6%
5	6.2%	50.6%	5	5.5%	50.7%	5	5.4%	49.9%	5	5.5%	51.1%
6	5.1%	55.7%	6	5.3%	56.0%	6	4.7%	54.6%	6	5.1%	56.2%
7	4.7%	60.4%	7	5.0%	61.0%	7	3.8%	58.4%	7	3.7%	59.9%
8	4.4%	64.9%	8	3.9%	64.9%	8	3.5%	62.0%	8	3.7%	63.6%
9	4.2%	69.0%	9	3.1%	68.0%	9	3.5%	65.5%	9	3.3%	66.9%
Other (76 companies)	31.0%	100.0%	Other (72 companies)	32.0%	100.0%	Other (75 companies)	34.5%	100.0%	Other (75 companies)	33.1%	100.0%

Figure 3-65 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies since 2012.

Figure 3-65 Marginal unit contribution to real-time load-weighted LMP (By parent company): 2011 through 2021

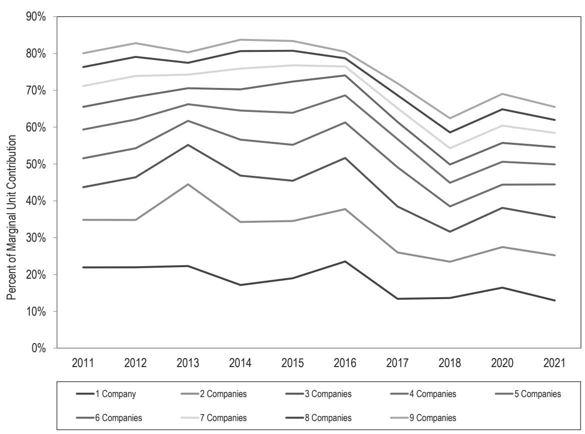


Table 3-131 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[186] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in 2021, the offers of one company contributed 6.4 percent of the day-ahead load-weighted average PJM system LMP and that the offers of the top four companies contributed 21.1 percent of the day-ahead load-weighted average PJM system LMP.

Table 3-131 Marginal resource contribution to day-ahead load-weighted LMP (By parent company): 2020 and 2021

2020						2021					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	10.5%	10.5%	1	10.9%	10.9%	1	6.4%	6.4%	1	7.7%	7.7%
2	10.4%	20.9%	2	9.5%	20.4%	2	5.2%	11.6%	2	6.4%	14.2%
3	5.7%	26.6%	3	8.8%	29.2%	3	5.1%	16.7%	3	5.0%	19.1%
4	4.8%	31.3%	4	5.3%	34.5%	4	4.5%	21.1%	4	4.6%	23.8%
5	4.5%	35.8%	5	5.0%	39.5%	5	4.4%	25.5%	5	4.5%	28.2%
6	4.3%	40.2%	6	4.4%	43.9%	6	4.4%	29.9%	6	3.8%	32.1%
7	3.9%	44.0%	7	4.1%	48.0%	7	3.9%	33.8%	7	3.4%	35.5%
8	3.7%	47.8%	8	3.3%	51.3%	8	3.6%	37.4%	8	3.1%	38.5%
9	3.7%	51.5%	9	3.0%	54.2%	9	3.5%	40.9%	9	3.0%	41.5%
Other (147 companies)	48.5%	100.0%	Other (144 companies)	45.8%	100.0%	Other (147 companies)	59.1%	100.0%	Other (143 companies)	58.5%	100.0%

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[187] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. A full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater

186 Id.

187 The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. The markup analysis does not include markup in start up or no load offers. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-132 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $2.19 per MWh in 2020 to $4.23 per MWh in 2021. The adjusted markup contribution of coal units in 2021 was $0.24 per MWh. The adjusted markup component of gas fired units in 2021 was $3.09 per MWh, an increase of $1.11 per MWh from 2020. The markup component of wind units was less than $0.0 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2021, among the wind units that were marginal, 77.8 percent had negative offer prices.

Table 3-132 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: 2020 and 2021[188]

		2020		2021	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.40)	$0.24	$0.71	$1.19
Gas	CC	$0.78	$1.61	$0.77	$2.12
Gas	CT	$0.24	$0.39	$0.32	$0.93
Gas	RICE	$0.02	$0.03	($0.00)	$0.01
Gas	Steam	($0.10)	($0.06)	($0.04)	$0.03
Landfill Gas	CT	$0.00	$0.00	($0.00)	($0.00)
Municipal Waste	RICE	$0.00	$0.00	$0.00	$0.00
Oil	CC	$0.00	$0.00	$0.00	$0.00
Oil	CT	($0.00)	$0.00	($0.00)	$0.01
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.03)	($0.03)	($0.07)	($0.06)
Other	Steam	($0.00)	($0.00)	$0.00	$0.00
Wind	Wind	($0.00)	($0.00)	($0.02)	($0.02)
Total		$0.50	$2.19	$1.69	$4.23

Markup Component of Real-Time Price

Table 3-133 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-134 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In 2021, when using unadjusted cost-based offers, 1.69 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $4.23 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In 2021, the peak markup component was highest in August, $2.71 per MWh using unadjusted cost-based offers and peak markup component was highest in October, $9.94 per MWh using adjusted cost-based offers. This corresponds to 11.8 percent of the real-time, peak, load-weighted, average LMP in August and 14.8 percent of the real-time peak load-weighted average LMP in October.

188 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-133 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2020 through 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.49	$0.94	$0.03	($0.46)	($0.30)	($0.60)
Feb	($0.15)	($0.00)	($0.28)	($0.53)	$0.06	($1.12)
Mar	($0.09)	$0.46	($0.66)	$0.02	$0.16	($0.13)
Apr	($0.07)	$0.17	($0.33)	($1.69)	($2.56)	($0.72)
May	$0.54	$1.03	$0.10	($0.02)	$0.62	($0.62)
Jun	$1.24	$2.02	$0.30	$1.75	$2.76	$0.58
Jul	$0.83	$1.75	($0.30)	$2.61	$3.37	$1.80
Aug	$1.80	$2.88	$0.70	$4.83	$6.68	$2.71
Sep	$0.47	$0.97	($0.08)	$3.30	$4.19	$2.34
Oct	$0.09	$0.71	($0.57)	$4.43	$5.52	$3.35
Nov	($0.01)	$0.72	($0.68)	$3.15	$4.12	$2.20
Dec	$0.37	$0.37	$0.37	$1.89	$2.46	$1.26
Total	$0.50	$1.08	($0.10)	$1.69	$2.41	$0.94

Table 3-134 Monthly markup components of real-time load-weighted LMP (Adjusted): 2020 through 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.21	$2.80	$1.60	$1.47	$1.73	$1.24
Feb	$1.57	$1.85	$1.30	$2.41	$3.21	$1.60
Mar	$1.44	$2.07	$0.81	$1.63	$1.85	$1.39
Apr	$1.43	$1.73	$1.11	($0.08)	($0.97)	$0.91
May	$1.98	$2.65	$1.39	$1.93	$2.75	$1.17
Jun	$2.77	$3.75	$1.58	$3.96	$5.22	$2.52
Jul	$2.70	$3.81	$1.33	$5.11	$6.20	$3.95
Aug	$3.61	$4.83	$2.35	$7.75	$9.92	$5.27
Sep	$1.89	$2.50	$1.22	$6.52	$7.71	$5.23
Oct	$1.76	$2.51	$0.95	$8.33	$9.94	$6.73
Nov	$1.68	$2.53	$0.88	$6.41	$7.70	$5.16
Dec	$2.46	$2.56	$2.37	$4.28	$4.92	$3.57
Total	$2.19	$2.90	$1.44	$4.23	$5.17	$3.24

Hourly Markup Component of Real-Time Prices

Figure 3-66 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2020 and 2021. Figure 3-67 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2020 and 2021.

Figure 3-66 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2020 and 2021

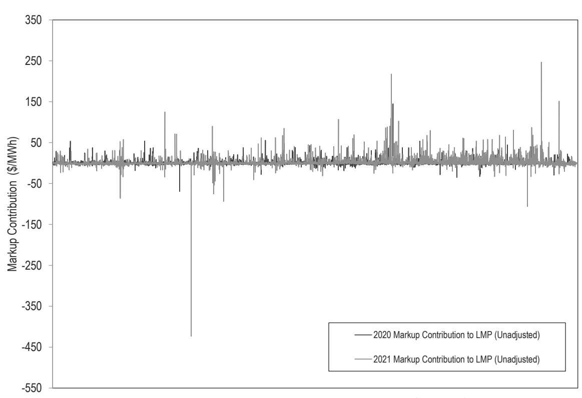
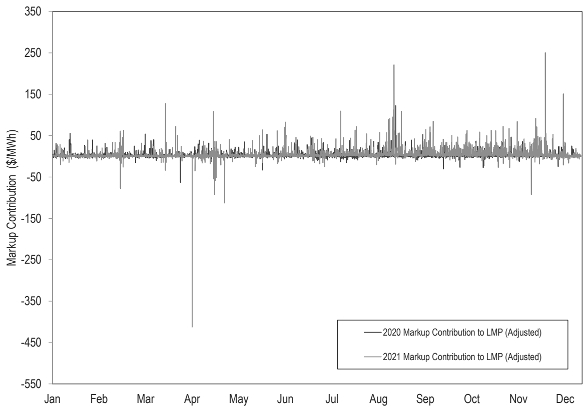


Figure 3-67 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2020 and 2021



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in 2020 and 2021 in Table 3-135 and for adjusted offers in Table 3-136.[189] The smallest zonal all hours average markup component using unadjusted offers in 2021, was in the ACEC Control Zone, 0.95 per MWh, while the highest was in the PEPCO Control Zone, $2.28 per MWh. The smallest zonal on peak average markup component using unadjusted offers in 2021, was in the ACEC Control Zone, 1.59 per MWh, while the highest was in the BGE Control Zone, $3.07 per MWh.

Table 3-135 Real-time average zonal markup component (Unadjusted): 2020 and 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.13	$0.29	($0.04)	$0.95	$1.59	$0.28
AEP	$0.17	$0.39	($0.06)	$1.86	$2.64	$1.06
APS	$0.20	$0.45	($0.06)	$1.89	$2.69	$1.08
ATSI	$0.20	$0.42	($0.04)	$1.87	$2.62	$1.10
BGE	$0.28	$0.60	($0.05)	$2.27	$3.07	$1.45
COMED	$0.13	$0.39	($0.14)	$1.75	$2.55	$0.92
DAY	$0.20	$0.42	($0.04)	$1.96	$2.72	$1.18
DOM	$0.18	$0.41	($0.06)	$1.99	$2.82	$1.14
DPL	$0.10	$0.28	($0.09)	$1.16	$1.89	$0.42
DUKE	$0.18	$0.41	($0.06)	$1.85	$2.57	$1.12
DUQ	$0.23	$0.49	($0.05)	$1.81	$2.52	$1.09
EKPC	$0.16	$0.41	($0.08)	$1.84	$2.56	$1.10
JCPLC	$0.13	$0.28	($0.04)	$1.09	$1.72	$0.45
MEC	$0.12	$0.28	($0.06)	$1.77	$2.84	$0.68
OVEC	$0.09	$0.32	($0.12)	$1.84	$2.42	$1.24
PE	$0.16	$0.34	($0.04)	$1.68	$2.52	$0.82
PECO	$0.11	$0.29	($0.08)	$0.98	$1.66	$0.30
PEPCO	$0.23	$0.50	($0.06)	$2.28	$3.00	$1.55
PPL	$0.11	$0.22	$0.01	$1.40	$2.19	$0.60
PSEG	$0.12	$0.28	($0.06)	$1.15	$1.79	$0.50
REC	$0.10	$0.24	($0.07)	$1.45	$2.21	$0.67

189 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-136 Real-time average zonal markup component (Adjusted): 2020 and 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.79	$0.99	$0.59	$3.16	$3.94	$2.37
AEP	$0.95	$1.24	$0.66	$4.53	$5.57	$3.47
APS	$0.99	$1.30	$0.66	$4.59	$5.65	$3.51
ATSI	$0.98	$1.27	$0.67	$4.53	$5.52	$3.52
BGE	$1.09	$1.46	$0.70	$5.28	$6.42	$4.10
COMED	$0.84	$1.18	$0.49	$4.30	$5.37	$3.20
DAY	$1.00	$1.29	$0.69	$4.76	$5.79	$3.69
DOM	$0.95	$1.24	$0.65	$4.84	$5.96	$3.69
DPL	$0.83	$1.03	$0.61	$3.44	$4.28	$2.58
DUKE	$0.95	$1.24	$0.65	$4.54	$5.53	$3.53
DUQ	$1.00	$1.33	$0.65	$4.43	$5.37	$3.46
EKPC	$0.95	$1.24	$0.66	$4.52	$5.50	$3.51
JCPLC	$0.83	$1.02	$0.62	$3.39	$4.16	$2.59
MEC	$0.86	$1.07	$0.64	$4.36	$5.75	$2.94
OVEC	$0.90	$1.21	$0.63	$4.46	$5.29	$3.61
PE	$0.91	$1.15	$0.65	$4.23	$5.30	$3.13
PECO	$0.82	$1.03	$0.59	$3.18	$3.97	$2.36
PEPCO	$1.01	$1.34	$0.67	$5.19	$6.21	$4.15
PPL	$0.83	$0.97	$0.68	$3.81	$4.84	$2.76
PSEG	$0.82	$1.03	$0.60	$3.49	$4.32	$2.64
REC	$0.79	$0.98	$0.58	$3.90	$4.93	$2.85

Markup by Real-Time Price Levels

Table 3-137 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-137 Real-time markup contribution (By load-weighted LMP category, unadjusted): 2020 and 2021

	2020		2021	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($0.53)	2.5%	($10.48)	0.0%
$10 to $15	($0.22)	25.9%	($1.56)	0.5%
$15 to $20	($0.43)	43.8%	($0.94)	12.0%
$20 to $25	$0.29	18.6%	($0.92)	20.1%
$25 to $50	$2.80	7.9%	$0.24	47.5%
$50 to $75	$7.69	1.0%	$4.70	13.8%
$75 to $100	$5.86	0.2%	$12.59	3.4%
$100 to $125	$6.26	0.0%	$16.47	1.5%
$125 to $150	$1.20	0.0%	$25.32	0.5%
>= $150	$2.85	0.0%	$29.36	0.7%

Table 3-138 Real-time markup contribution (By load-weighted LMP category, adjusted): 2020 and 2021

	2020		2021	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($0.05)	2.6%	($9.88)	0.0%
$10 to $15	$0.41	25.7%	($0.35)	0.5%
$15 to $20	$0.41	44.1%	$0.52	12.0%
$20 to $25	$1.26	18.5%	$0.92	20.1%
$25 to $50	$3.89	7.7%	$2.70	47.5%
$50 to $75	$9.21	1.0%	$8.39	13.8%
$75 to $100	$6.85	0.2%	$16.70	3.4%
$100 to $125	$7.09	0.0%	$20.76	1.5%
$125 to $150	$3.18	0.0%	$29.93	0.5%
>= $150	$3.62	0.0%	$33.26	0.7%

Markup by Company

Table 3-139 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In 2021, when using unadjusted cost-based offers, the markup of one company accounted for 1.5 percent of the load-weighted average LMP, the markup of the top five companies accounted for 4.1 percent of the load-weighted average LMP and the markup of all companies accounted for 4.2 percent of the load-weighted average LMP. The top five companies' markup contribution to the load-weighted average LMP and the dollar values of their markup increased in 2021. The markup contribution to the load-weighted average LMP and share of the markup contribution to the load-weighted average LMP also increased in 2021. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-139 Markup component of real-time load-weighted average LMP by Company: 2020 and 2021

	2020				2021			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.39	1.8%	$0.64	2.9%	$0.59	1.5%	$0.80	2.0%
Top 2 Companies	$0.55	2.5%	$0.88	4.0%	$0.98	2.5%	$1.53	3.9%
Top 3 Companies	$0.68	3.1%	$1.11	5.1%	$1.30	3.3%	$1.98	5.0%
Top 4 Companies	$0.79	3.6%	$1.31	6.0%	$1.49	3.7%	$2.28	5.7%
Top 5 Companies	$0.88	4.0%	$1.45	6.7%	$1.65	4.1%	$2.54	6.4%
All Companies	$0.50	2.3%	$2.19	10.0%	$1.69	4.2%	$4.23	10.6%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead load-weighted average LMP by primary fuel and unit type is shown in Table 3-140. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 35.2 percent of marginal resources, INCs were 17.9 percent of marginal resources and DECs were 27.1 percent of marginal resources in 2021.

The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer and the cost-based offer excluding the 10 percent adder. Table 3-140 shows the markup component of LMP for marginal generating resources. Generating resources were only 19.5 percent of marginal resources in 2021. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources increased for coal fired steam units from $0.15 to $1.08 per MWh and increased for gas fired CC units from $0.93 to $1.48 per MWh.

Table 3-140 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: 2020 and 2021

		2020			2021		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	($0.50)	$0.15	35.1%	$0.52	$1.08	31.5%
Gas	CC	$0.51	$0.93	53.4%	$0.44	$1.48	53.4%
Gas	CT	$0.03	$0.04	1.5%	$0.02	$0.05	2.4%
Gas	RICE	($0.00)	($0.00)	0.4%	($0.00)	$0.00	0.9%
Gas	Steam	($0.07)	($0.03)	3.7%	($0.04)	$0.01	3.3%
Municipal Waste	RICE	$0.00	$0.00	0.1%	$0.00	$0.00	0.2%
Oil	CC	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Oil	CT	($0.00)	($0.00)	0.8%	$0.03	$0.04	0.8%
Oil	RICE	$0.00	$0.00	0.0%	$0.00	$0.00	0.1%
Oil	Steam	($0.01)	($0.01)	0.1%	($0.09)	($0.08)	0.1%
Other	Solar	$0.00	$0.00	0.1%	$0.03	$0.03	0.2%
Other	Steam	($0.00)	($0.00)	0.3%	$0.00	$0.00	0.2%
Uranium	Steam	$0.00	$0.00	1.7%	$0.00	$0.00	0.3%
Water	Hydro	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Wind	Wind	$0.01	$0.01	2.8%	$0.31	$0.31	6.6%
Total		($0.04)	$1.08	100.0%	$1.22	$2.93	100.0%

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-141 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. In 2021, when using unadjusted cost-based offers, $1.22 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2021, the peak markup component was highest in October, $8.06 per MWh using unadjusted cost-based offers.

Table 3-141 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: 2020 and 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.03)	$0.27	($0.35)	($0.41)	($0.19)	($0.59)
Feb	($0.23)	($0.08)	($0.38)	($0.30)	$2.25	($2.91)
Mar	($0.22)	($0.21)	($0.23)	$0.62	$0.56	$0.69
Apr	($0.27)	($0.19)	($0.36)	$0.38	$0.84	($0.14)
May	($0.19)	$0.17	($0.52)	$1.06	$1.26	$0.88
Jun	$0.09	$0.49	($0.41)	$0.16	$0.41	($0.13)
Jul	$0.12	$0.71	($0.62)	$1.97	$3.19	$0.65
Aug	$0.13	$0.80	($0.59)	$1.59	$2.32	$0.73
Sep	($0.01)	$0.55	($0.63)	$2.31	$3.44	$1.07
Oct	$0.17	$0.51	($0.19)	$4.87	$8.06	$1.66
Nov	($0.18)	$0.33	($0.67)	$2.36	$2.12	$2.60
Dec	$0.07	$0.38	($0.24)	$0.37	$1.23	($0.62)
Total	($0.04)	$0.34	($0.44)	$1.22	$2.10	$0.29

Table 3-142 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In 2021, when using adjusted cost-based offers, $2.93 per MWh of the PJM day-ahead, load-weighted average LMP was attributable to markup. In 2021, the peak markup component was highest in October, $9.85 per MWh using adjusted cost-based offers.

Table 3-142 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: 2020 and 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.34	$1.64	$1.03	$1.16	$1.31	$1.03
Feb	$1.02	$1.22	$0.82	$2.21	$4.69	($0.33)
Mar	$0.97	$1.04	$0.90	$1.78	$1.72	$1.84
Apr	$0.70	$0.91	$0.47	$1.64	$1.98	$1.26
May	$0.72	$1.00	$0.47	$2.45	$2.58	$2.33
Jun	$1.08	$1.46	$0.60	$1.49	$1.75	$1.19
Jul	$1.28	$1.83	$0.59	$3.62	$4.73	$2.41
Aug	$1.20	$1.87	$0.48	$3.40	$3.99	$2.71
Sep	$0.95	$1.51	$0.34	$4.25	$5.13	$3.29
Oct	$1.14	$1.39	$0.86	$6.89	$9.85	$3.91
Nov	$0.93	$1.34	$0.54	$4.44	$4.11	$4.77
Dec	$1.44	$1.69	$1.18	$2.07	$2.92	$1.11
Total	$1.08	$1.45	$0.70	$2.93	$3.71	$2.10

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-143. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-144. The smallest zonal all hours average markup component using adjusted cost-based offers for 2021 was in the DPL Zone, $2.21 per MWh, while the highest was in the BGE Control Zone, $3.52 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the DPL Control Zone, $2.27 per MWh, while the highest was in the EKPC Control Zone, $4.86 per MWh.

Table 3-143 Day-ahead average zonal markup component (Unadjusted): 2020 and 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.24	$0.56	($0.10)	$0.88	$1.44	$0.29
AEP	($0.17)	$0.21	($0.57)	$1.20	$2.10	$0.27
APS	($0.17)	$0.21	($0.56)	$1.12	$2.03	$0.15
ATSI	($0.07)	$0.34	($0.51)	$0.89	$1.56	$0.18
BGE	($0.25)	$0.17	($0.69)	$1.75	$3.15	$0.30
COMED	($0.10)	$0.33	($0.55)	$1.14	$1.81	$0.43
DAY	($0.00)	$0.56	($0.62)	$1.39	$2.42	$0.28
DOM	($0.09)	$0.41	($0.61)	$1.50	$2.53	$0.45
DPL	$0.17	$0.39	($0.06)	$0.51	$0.51	$0.51
DUKE	$0.01	$0.67	($0.69)	$1.30	$2.23	$0.33
DUQ	($0.19)	$0.16	($0.56)	$0.95	$1.61	$0.26
EKPC	($0.07)	$0.45	($0.60)	$2.32	$4.48	$0.15
JCPLC	$0.18	$0.46	($0.14)	$0.85	$1.38	$0.25
MEC	$0.00	$0.00	$0.01	$1.04	$1.79	$0.21
OVEC	$0.22	$0.62	($0.31)	$1.24	$1.76	$0.72
PE	$0.10	$0.36	($0.21)	$0.79	$1.30	$0.20
PECO	$0.20	$0.47	($0.09)	$0.73	$1.08	$0.36
PEPCO	($0.36)	($0.06)	($0.70)	$1.59	$2.79	$0.29
PPL	$0.50	$0.70	$0.29	$0.86	$1.39	$0.29
PSEG	$0.18	$0.44	($0.10)	$0.84	$1.31	$0.33
REC	$0.21	$0.52	($0.14)	$0.84	$1.37	$0.23

Table 3-144 Day-ahead average zonal markup component (Adjusted): 2020 and 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.33	$1.66	$0.99	$2.80	$3.36	$2.22
AEP	$0.97	$1.30	$0.61	$2.93	$3.74	$2.08
APS	$0.94	$1.28	$0.58	$2.90	$3.73	$2.03
ATSI	$1.07	$1.46	$0.65	$2.73	$3.30	$2.12
BGE	$0.86	$1.23	$0.47	$3.52	$4.75	$2.22
COMED	$1.01	$1.43	$0.57	$2.83	$3.56	$2.06
DAY	$1.19	$1.72	$0.62	$3.24	$4.19	$2.20
DOM	$1.11	$1.68	$0.52	$3.27	$4.14	$2.38
DPL	$1.26	$1.45	$1.06	$2.21	$2.27	$2.14
DUKE	$1.15	$1.75	$0.51	$3.02	$3.81	$2.17
DUQ	$0.90	$1.20	$0.58	$2.74	$3.30	$2.15
EKPC	$1.05	$1.50	$0.59	$3.29	$4.86	$1.72
JCPLC	$1.29	$1.58	$0.98	$2.78	$3.31	$2.19
MEC	$1.05	$1.02	$1.08	$2.69	$3.33	$1.98
OVEC	$1.36	$1.84	$0.74	$3.15	$3.54	$2.75
PE	$1.12	$1.36	$0.84	$2.54	$3.00	$2.02
PECO	$1.28	$1.54	$1.00	$2.57	$2.93	$2.18
PEPCO	$0.75	$1.00	$0.48	$3.38	$4.45	$2.23
PPL	$1.54	$1.74	$1.34	$2.59	$3.07	$2.08
PSEG	$1.28	$1.53	$1.00	$2.73	$3.20	$2.22
REC	$1.30	$1.58	$0.97	$2.64	$3.16	$2.04

Markup by Day-Ahead Price Levels

Table 3-145 and Table 3-146 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-145 Day-ahead average markup component (By LMP category, unadjusted): 2020 and 2021

	2020		2021	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	($0.01)	1.4%	$0.00	0.0%
$10 to $15	($0.08)	17.6%	($0.00)	0.1%
$15 to $20	($0.19)	40.2%	$0.02	8.7%
$20 to $25	($0.01)	24.2%	($0.08)	20.0%
$25 to $50	$0.19	16.0%	$0.41	51.5%
$50 to $75	$0.06	0.6%	$0.57	15.8%
$75 to $100	$0.00	0.0%	$0.22	2.9%
$100 to $125	$0.00	0.0%	$0.03	0.6%
$125 to $150	$0.00	0.0%	($0.00)	0.3%
>= $150	$0.00	0.0%	$0.04	0.1%

Table 3-146 Day-ahead average markup component (By LMP category, adjusted): 2020 and 2021

	2020		2021	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	1.4%	$0.00	0.0%
$10 to $15	$0.05	17.6%	($0.00)	0.1%
$15 to $20	$0.27	40.2%	$0.10	8.7%
$20 to $25	$0.32	24.2%	$0.19	20.0%
$25 to $50	$0.37	16.0%	$1.34	51.5%
$50 to $75	$0.07	0.6%	$0.90	15.8%
$75 to $100	$0.00	0.0%	$0.27	2.9%
$100 to $125	$0.00	0.0%	$0.05	0.6%
$125 to $150	$0.00	0.0%	$0.01	0.3%
>= $150	$0.00	0.0%	$0.05	0.1%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment evaluates the extent to which that participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[190]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, P is the market price, and MC is the average marginal cost of production. This is called the Lerner Index. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. As HHI decreases, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices can reach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose higher prices on customers. The Lerner Index is a measure of market power that connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories may understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level would imply substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4. Using the Lerner Index, the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[191]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

190 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

191 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $38.09 per MWh and an average HHI of 742 in 2021, average PJM prices would theoretically range from $47 to $61 per MWh using the elasticity range of -0.2 to -0.4.[192] The theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging $39.78 per MWh with markups at 4.2 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-147 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In 2021, 4.7 percent of real-time marginal unit intervals and 3.6 percent of day-ahead marginal unit hours included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit.

Table 3-147 Percent of real-time marginal unit intervals with markup and local market power: 2021

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	28.7%	5.5%	34.2%	35.2%	9.2%	44.3%
Zero Markup	26.5%	6.5%	33.0%	15.6%	8.2%	23.8%
$0 to $5	18.9%	1.7%	20.6%	20.2%	2.9%	23.1%
$5 to $10	4.2%	0.5%	4.7%	3.4%	0.6%	3.9%
$10 to $15	2.0%	0.5%	2.4%	1.2%	0.2%	1.4%
$15 to $20	1.9%	0.2%	2.1%	0.8%	0.2%	1.0%
$20 to $25	0.5%	0.2%	0.7%	0.4%	0.2%	0.6%
$25 to $50	1.2%	0.4%	1.6%	0.9%	0.4%	1.3%
$50 to $75	0.4%	0.1%	0.5%	0.1%	0.1%	0.2%
$75 to $100	0.1%	0.0%	0.1%	0.1%	0.1%	0.2%
Above $100	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%
Total Positive Markup	29.1%	3.6%	32.7%	27.2%	4.7%	31.9%
Total	84.4%	15.6%	100.0%	78.0%	22.0%	100.0%

The markup of marginal units was zero or negative in 68.1 percent of real-time marginal unit intervals and 67.2 percent of day-ahead marginal unit intervals in 2021. Pivotal suppliers in the aggregate market also set prices with high markups in 2021. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.

192 The average HHI is found in Table 3-95. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-69.

Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Effective November 1, 2020, UTC transactions are allocated day-ahead and real-time uplift charges, and are treated for uplift purposes as equivalent to a decrement bid (DEC) at the sink point of the UTC.[2]

Uplift is an inherent part of the PJM market design. Part of uplift is the result of the nonconvexity of power production costs. Uplift payments cannot be eliminated, but uplift payments should be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[3] [4] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design incorporates efficient prices with minimal uplift payments. Actual results in PJM do not minimize actual uplift payments. There are improvements to the market design and uplift rules that could further reduce uplift payments while maintaining efficient prices.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the real-time energy market. The current payment structure for DR is an inefficient element of the PJM market design.[5]

Overview

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $87.4 million, or 96.2 percent, in 2021 compared to 2020, from $90.9 million to $178.3 million.
- **Energy Uplift Charges Categories.** The increase of $87.4 million in 2021 was comprised of a $4.4 million increase in day-ahead operating reserve charges, an $82.5 million increase in balancing operating reserve charges, and a $0.5 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.016 per MWh in the Eastern Region. Real-time load and exports paid $0.084 per MWh. Deviations (which include deviations from load, imports, exports, generators, INCs, DECs and UTCs) paid $0.467 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid $0.210 per MWh in the Western Region. Real-time load and exports paid $0.073 per MWh. Deviations (which include deviations from load,

1 Loss exists when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers, and the unit is following PJM instructions including both commitment and dispatch instructions. There is no corresponding assurance required when units are self scheduled or not following PJM dispatch instructions.

2 See 172 FERC ¶ 61,046 (2020).

3 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

4 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

5 Demand response payments are addressed in Section 6: Demand Response.

imports, exports, generators, INCs, DECs and UTCs) paid $0.416 per MWh in the Western Region.

- **Reactive Services Rates.** PPL and COMED were the two zones with the highest local reactive services (voltage support) rates, excluding reactive capability payments. PPL had a rate of $0.017 per MWh and COMED had a rate of $0.002 per MWh.

Energy Uplift Credits

- **Types of credits.** In 2021, energy uplift credits were $178.3 million, including $13.7 million in day-ahead generator credits, $127.5 million in balancing generator credits, $30.3 million in lost opportunity cost credits, and $4.8 million in local constraint control credits. Dispatch differential lost opportunity credits, implemented as part of fast start pricing on September 1, 2021, were $0.7 million.
- **Types of units.** In 2021, coal units received 72.0 percent of day-ahead generator credits, and combustion turbines received 92.8 percent of balancing generator credits and 95.6 percent of lost opportunity cost credits. Since September 1, 2021, combined cycle units and combustion turbines have received 66.6 percent of dispatch differential lost opportunity credits.
- **Economic and Noneconomic Generation.** In 2021, 89.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 65.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2021, 0.2 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 50.6 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** In 2021, the top 10 units receiving energy uplift credits received 41.6 percent of all credits and the top 10 organizations received 87.3 percent of all credits. The HHI for day-ahead operating reserves was 7876, the HHI for balancing operating reserves was 2637 and the HHI for lost opportunity cost was 5728, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $11.0 million or 56.8 percent, in 2021 compared to 2020, from $19.3 million to $30.3 million.
- Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 96.7 percent of the $17.2 million. The day-ahead generation paid LOC credits for this reason decreased by 718.3 GWh or 55.7 percent during 2021, compared to 2020, from 1,288.7 GWh to 570.4 GWh.
- **Following Dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $14.8 million, of which PJM has resettled $1.5 million, or 9.9 percent.
- **Daily Uplift.** In 2021, balancing operating reserve charges would have been $27.0 million or 21.2 percent lower if they had been calculated on a daily basis rather than a segmented basis. In 2020, balancing operating reserve credits would have been $10.7 million or 18.5 percent lower if they had been calculated on a daily basis rather than a segmented basis. Uplift was designed to be charged on a daily basis and not on an, intraday segmented basis.

Geography of Charges and Credits

- In 2021, 88.9 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 4.3 percent by transactions at hubs and aggregates, and 6.7 percent by transactions at interchange interfaces.
- In 2021, generators in the Eastern Region received 38.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2021, generators in the Western Region received 58.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2021, external generators received 3.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the day-ahead energy market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Partially adopted, 2019.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead uplift, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported Q2, 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)

- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift (operating reserve) confidentiality rules in order to allow the disclosure of complete information about the level of uplift (operating reserve charges) by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[6])
- The MMU recommends that PJM eliminate the exemption for CTs and diesels from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus start up and no load costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create

6 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. 166 FERC ¶ 61,210. PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its CT price setting logic. The same is true of fast start pricing. The same is true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing proposal (limited convex hull pricing). Fast start pricing was approved by FERC and implemented on September 1, 2021.[7] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[8] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability in the day-ahead market.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[9] The uplift payments for UTCs began on November 1, 2020.[10] This had been a longstanding recommendation of the MMU.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. they do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM

7 See 173 FERC ¶ 61,244 (2020).

8 On March 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280.

9 See 172 FERC ¶ 61,046.

10 On October 17, 2017, PJM filed a proposed tariff change at FERC to allocate uplift to UTC transactions in the same way uplift is allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. See 162 FERC ¶ 61,019 (2018).

needs to define and implement rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $14.8 million of incorrect uplift credits.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists and to stop creating incentives for inflexibility.

Energy Uplift Credits Results

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. Energy uplift payments currently also result, incorrectly, from decisions by units to maintain an output level not consistent with PJM dispatch instructions. The resulting costs not covered by energy revenues are collected as energy uplift.

Table 4-1 shows the totals for each credit category for 2020 and 2021.[11] In 2021, energy uplift credits increased by $87.4 million or 96.2 percent compared to 2020.

The dispatch differential lost opportunity cost is a new credit in the balancing market, introduced as a result of fast start pricing on September 1, 2021. The credit is intended to address the situation in which resources are dispatched down to accommodate inflexible fast start resources. Units eligible for the dispatch differential credit include pool scheduled and dispatchable, self scheduled units dispatched to an output below the output that would be economic for them at the prevailing fast start prices in the real-time market. Because fast start pricing was introduced on September 1, 2021, Table 4-1 reflects only four months of data for the dispatch differential lost opportunity cost credit.

11 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 12, 2022.

Table 4-1 Energy uplift credits by category: 2020 and 2021[12]

Category	Type	2020 Credits (Millions)	2021 Credits (Millions)	Change	Percent Change	2020 Share	2021 Share
Day-Ahead	Generators	$9.3	$13.7	$4.4	47.3%	10.2%	7.7%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	($0.0)	NA	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$58.2	$127.5	$69.4	119.2%	64.0%	71.5%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Local Constraints Control	$3.4	$4.8	$1.4	41.1%	3.8%	2.7%
	Lost Opportunity Cost	$19.4	$30.3	$11.0	56.8%	21.3%	17.0%
	Dispatch Differential Lost Opportunity Cost	NA	$0.69	$0.0	NA	0.0%	0.4%
Reactive Services	Day-Ahead	$0.1	$0.3	$0.2	315.1%	0.1%	0.1%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Reactive Services	$0.4	$0.6	$0.3	72.9%	0.4%	0.4%
	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	($0.0)	NA	0.0%	0.0%
	Testing	$0.2	$0.3	$0.1	36.1%	0.3%	0.2%
Total		$90.9	$178.3	$87.4	96.2%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for 2020 and 2021. Uplift credits increased for all unit types. A combination of factors led to increased uplift payments in 2021, including increased real-time generation from CTs, higher natural gas prices, and increased load.

Uplift credits paid to combustion turbines increased by $79.1 million or 106.5 percent in 2021 compared to the same period in 2020. This increase can largely be attributed to higher natural gas prices, higher energy prices, and higher reliance on CT generation in real time.

Uplift credits paid to coal units increased by $2.2 million or 19.5 percent in 2021 compared with the same period in 2020. These high uplift payments can largely be attributed to a small number of coal units in the BGE and PEPCO Zones committed for reliability.

In 2021, uplift credits to wind units were $0.3 million, down by 48.0 percent compared to 2020.

Table 4-2 Total energy uplift credits by unit type: 2020 and 2021[13 14]

Unit Type	2020 Credits (Millions)	2021 Credits (Millions)	Change	Percent Change	2020 Share	2021 Share
Combined Cycle	$2.5	$5.9	$3.4	134.5%	2.8%	3.3%
Combustion Turbine	$74.3	$153.4	$79.1	106.5%	81.8%	86.1%
Diesel	$0.8	$1.6	$0.8	106.9%	0.9%	0.9%
Hydro	$0.0	$0.2	$0.1	1,784.7%	0.0%	0.1%
Nuclear	$0.0	$0.0	($0.0)	(66.5%)	0.0%	0.0%
Solar	$0.0	$0.0	$0.0	885.1%	0.0%	0.0%
Steam - Coal	$11.3	$13.5	$2.2	19.5%	12.4%	7.6%
Steam - Other	$1.3	$3.3	$2.0	159.3%	1.4%	1.9%
Wind	$0.7	$0.3	($0.3)	(48.0%)	0.7%	0.2%
Total	$90.9	$178.3	$87.4	96.2%	100.0%	100.0%

12 Year to year change is rounded to one tenth of a million, and includes values less than $0.05 million.
13 Table 4-2 does not include balancing imports credits and load response credits in the total amounts.
14 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in 2021. The characteristics of the different unit types explain why uplift in specific categories is paid primarily to specific unit types. For example, the majority of day-ahead credits, 82.0 percent, went to steam units because steam units tend to be longer lead time units that are committed before the operating day. If a steam unit is needed for reliability and it is uneconomic, it will be committed in the day-ahead energy market and receive day-ahead credits. Combustion turbines, which, unlike other unit types, can be committed and decommitted in the real-time market, received 92.8 percent of balancing credits and 93.3 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may require balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines committed in the day-ahead market but not committed in real time receive lost opportunity credits to cover the profits they would have made had they operated in real time.

Table 4-3 Energy uplift credits by unit type: 2021

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services	Dispatch Differential Lost Opportunity Cost
Combined Cycle	11.2%	2.6%	0.0%	1.1%	1.7%	16.5%	0.0%	41.4%	30.8%
Combustion Turbine	6.7%	92.8%	0.0%	97.3%	93.3%	81.2%	0.0%	58.6%	35.8%
Diesel	0.1%	0.7%	0.0%	1.1%	2.2%	0.2%	0.0%	0.0%	0.4%
Hydro	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	17.1%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	72.0%	2.7%	0.0%	0.0%	0.6%	0.1%	0.0%	0.0%	10.3%
Steam - Other	10.0%	1.2%	0.0%	0.4%	1.4%	2.1%	0.0%	0.0%	1.2%
Wind	0.0%	0.1%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	4.1%
Total (Millions)	$13.7	$127.5	$0.0	$4.8	$30.3	$0.9	$0.0	$0.3	$0.7

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the day-ahead energy market that would otherwise not have been committed in the day-ahead market when needed in real time to address reliability issues. Such reliability issues include reactive transfer interface control needed to maintain system reliability in a zone or reactive service.[15] Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[16] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal.

Table 4-4 shows total day-ahead generation and the subset of that generation committed for reliability by PJM. Day-ahead generation committed for reliability by PJM increased by 106.1 percent from 2020 to 2021, from 665.7 GWh in 2020 to 1,371.7 GWh. The increase in day-ahead generation committed for reliability by PJM was due to an increased need to commit uneconomic units in the PEPCO and BGE Zones for reliability.

15 See OA Schedule 1 § 3.2.3(b).
16 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 16, 2018) at 33, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

Table 4-4 Day-ahead generation committed for reliability (GWh): 2020 and 2021

	2020			2021			
	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	Percent Change of PJM Day-Ahead Must Run Generation
Jan	71,116	0	0.0%	73,635	95	0.1%	NA
Feb	65,827	5	0.0%	71,354	13	0.0%	177.1%
Mar	63,058	6	0.0%	64,713	209	0.3%	3,352.1%
Apr	55,091	41	0.1%	57,137	13	0.0%	(68.1%)
May	58,114	117	0.2%	60,957	26	0.0%	(78.0%)
Jun	69,651	60	0.1%	72,987	126	0.2%	110.0%
Jul	85,585	63	0.1%	80,025	103	0.1%	63.5%
Aug	79,173	88	0.1%	81,744	86	0.1%	(2.7%)
Sep	65,105	145	0.2%	66,913	410	0.6%	182.2%
Oct	59,974	107	0.2%	61,610	15	0.0%	(85.5%)
Nov	60,078	7	0.0%	62,746	181	0.3%	2,525.5%
Dec	71,591	27	0.0%	69,036	96	0.1%	257.9%
Total	804,363	666	0.1%	822,857	1,372	0.2%	106.1%

Pool scheduled units and units committed for reliability are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift (operating reserve credits). Total day-ahead operating reserve credits in 2021 were $13.7 million. The top 10 units received $10.0 million or 73.2 percent of all day-ahead operating reserve credits. These units were large units with operating parameters less flexible than PLS parameters, including long minimum run times.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run in the day-ahead market and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-5 shows the total day-ahead generation committed for reliability by PJM by category. In 2021, 50.6 percent of the day-ahead generation committed for reliability by PJM was paid operating reserve credits, 49.8 percent was paid day-ahead operating reserve credits and 0.8 percent was paid reactive services credits. The remaining 49.4 percent of the day-ahead generation committed for reliability was economic, meaning that the generation was not paid operating reserve credits because prices covered the generators' offers.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): 2021

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	7.0	44.3	43.2	94.6
Feb	1.3	4.1	7.5	12.9
Mar	0.0	179.6	29.5	209.1
Apr	0.0	7.2	5.9	13.1
May	0.0	20.6	5.1	25.8
Jun	0.0	101.8	23.8	125.6
Jul	0.0	16.9	85.6	102.5
Aug	0.0	30.7	54.9	85.6
Sep	2.7	160.2	246.9	409.8
Oct	0.0	13.1	2.4	15.5
Nov	0.0	45.0	135.8	180.8
Dec	0.0	60.2	36.2	96.4
Total	11.0	683.7	677.0	1,371.7
Share	0.8%	49.8%	49.4%	100.0%

Total day-ahead operating reserve credits in 2021 were $13.7 million, of which $7.5 million or 54.8 percent was paid to units committed for reliability by PJM, and not scheduled to provide reactive services. An additional 5.1 percent, or $0.7 million, was paid to units scheduled to provide reactive services.

Balancing Operating Reserve Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover their operating costs from market revenues. BOR credits are calculated as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits) and its real-time offer (startup, no load, and energy offer). Combustion turbines (CTs) received $118.3 million or 92.8 percent of all balancing operating reserve (BOR) credits in 2021. The majority of these credits, 98.6 percent, are paid to CTs that are committed in real time either without or outside of a day-ahead schedule.[17] Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day.

Uplift is also higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions. PJM apparently considers that units that start when requested and turn off when requested to be operating as requested by PJM regardless of how well the units follow the dispatch signal. Units should be disqualified from receiving uplift when the PJM dispatcher is able to identify units that are not following the dispatch signals, and after agreement with the generator, the dispatch reason is changed to self scheduled. PJM dispatchers should not be required to decide which units qualify for uplift.

PJM's position is illogical and PJM's definition of units not operating as requested is illogical. The logical definition of operating as requested includes both start and shutdown when requested and that units should followed their dispatch signal. Both should be required in order to receive uplift. Paying uplift to units not following dispatch does not provide an incentive for flexibility. The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch, instead of relying on PJM dispatchers' manual determinations, to evaluate eligibility for receiving balancing operating reserve credits and for assessing generator deviations. As part of the metric, the MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.

Balancing operating reserve credits for generators increased by 119.2 percent in 2021 compared to 2020. Higher natural gas prices and higher LMPs combined with PJM's need to run CTs more frequently resulted in increased balancing operating reserve credits during the 2021. The overall increase in credits in the DOM, COMED, and AEP Zones accounted for 60.0 percent of the total annual increase in balancing operating reserve credits.

Table 4-6 shows the monthly day-ahead and real-time generation by combustion turbines. In 2021, generation by combustion turbines was 31.2 percent higher in the real-time energy market than in the day-ahead energy market, although this varied by month. Table 4-6 shows that only 2.2 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 39.0 percent of generation from combustion turbines in the real-time market was uneconomic and required $118.3 million in BOR credits. This increase in uneconomic real-time generation resulted in increased BOR credits during 2021.

17 Operating outside of a day-ahead schedule refers to units that operate for a period either before or after their day-ahead schedule, or are committed in the real-time market and do not have a day-ahead schedule for any part of the day.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines eligible for operating reserve credits: 2021

Month	Day-Ahead Generation (GWh)	Percent of Day-Ahead Generation that was Noneconomic	Day-Ahead Generator Credits (Millions)	Real-Time Generation (GWh)	Percent of Real-Time Generation that was Noneconomic	Balancing Generator Credits (Millions)	Ratio of Day-Ahead to Real-Time Generation
Jan	240	6.5%	$0.0	483	62.7%	$4.4	0.5
Feb	298	5.8%	$0.1	485	57.4%	$9.9	0.6
Mar	309	2.1%	$0.1	471	51.6%	$4.5	0.7
Apr	662	2.1%	$0.0	1,270	62.5%	$16.0	0.5
May	845	1.7%	$0.2	890	48.5%	$5.0	0.9
Jun	1,541	2.3%	$0.0	2,042	39.3%	$12.2	0.8
Jul	1,767	2.7%	$0.1	2,514	38.4%	$16.7	0.7
Aug	2,300	2.7%	$0.3	3,190	34.0%	$18.1	0.7
Sep	1,027	1.3%	$0.0	1,144	21.8%	$3.6	0.9
Oct	1,430	1.9%	$0.0	1,803	28.5%	$11.0	0.8
Nov	1,652	1.1%	$0.1	1,734	35.5%	$13.0	1.0
Dec	529	1.6%	$0.0	497	33.5%	$3.9	1.1
Total	12,599	2.2%	$0.9	16,524	39.0%	$118.3	0.8

Balancing operating reserve credits to generators in 2021 were $118.3 million, of which $116.0 million, or 91.5 percent, was paid to combustion turbines operating without or outside a day-ahead schedule (Table 4-7).

Table 4-7 and Table 4-8 show real-time generation by combustion turbines by day-ahead commitment status in 2021 and 2020. CTs that operated on a day-ahead schedule during 2021 constituted 56.2 percent of real-time generation by CTs, of which 28.0 percent (15.7 percent of real-time generation) was uneconomic in the real-time market and received $1.6 million in BOR credits. CTs that operated on a day-ahead schedule in 2020 constituted 69.4 percent of real-time generation by CTs, of which 22.0 percent (15.3 percent of real-time generation) was uneconomic in the real-time market and received zero BOR credits.

In 2021, 43.8 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 53.1 percent (23.3 percent of real-time generation) was uneconomic in the real-time market and received $ 116.6 million in BOR credits. In 2020, 30.6 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 46.5 percent (14.2 percent of real-time generation) was uneconomic in the real-time market and received $ 116.6 million in BOR credits.

In 2021, real-time CT generation operating consistent with their day-ahead schedule decreased significantly compared to 2020, while real-time generation operating outside of a day-ahead schedule increased significantly. This shift of real-time generation operating consistent with their day-ahead schedule to real-time generation operating outside of a day-ahead schedule is a major contributing factor to the increase of BOR. Balancing operating reserves for real-time generation committed on a day-ahead schedule are calculated differently than for real-time generation committed outside of a day-ahead schedule, and this difference resulted in increased credits.

CTs that operate on a day-ahead schedule tend to receive lower BOR credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units because the day-ahead model optimizes the system for all 24 hours unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other) while in real time there are shorter segments defined by the minimum run time. Losses during the minimum run time segment are not offset by profits made in other segments on that day.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including differences in the hourly pattern of load, and differences in interchange transactions. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different optimization time periods used in the day-ahead and real-time markets.

Table 4-7 Real-time generation by combustion turbines by day-ahead commitment: 2021

	Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month	Generation (GWh)	Share of Real-Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)
Jan	154	31.8%	44.2%	$0.1	330	68.2%	71.3%	$4.3
Feb	184	38.0%	32.3%	$0.2	301	62.0%	72.8%	$9.7
Mar	214	45.5%	37.1%	$0.1	257	54.5%	63.7%	$4.4
Apr	511	40.2%	44.9%	$0.1	759	59.8%	74.4%	$15.9
May	528	59.3%	41.1%	$0.0	362	40.7%	59.3%	$4.9
Jun	1,153	56.4%	30.6%	$0.2	890	43.6%	50.5%	$12.0
Jul	1,447	57.5%	28.4%	$0.3	1,068	42.5%	51.9%	$16.5
Aug	1,908	59.8%	22.9%	$0.3	1,282	40.2%	50.4%	$17.8
Sep	792	69.2%	19.2%	$0.1	352	30.8%	27.6%	$3.4
Oct	1,122	62.2%	22.8%	$0.2	681	37.8%	38.0%	$10.8
Nov	977	56.3%	27.2%	$0.1	757	43.7%	46.2%	$12.9
Dec	291	58.5%	24.4%	$0.0	206	41.5%	46.4%	$3.9
Total	9,280	56.2%	28.0%	$1.6	7,244	43.8%	53.1%	$116.6

Table 4-8 Real-time generation by combustion turbines by day-ahead commitment: 2020

	Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month	Generation (GWh)	Share of Real-Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real-Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)
Jan	363	66.1%	3.8%	$0.0	186	33.9%	36.4%	$1.5
Feb	241	76.1%	4.3%	$0.0	76	23.9%	32.3%	$0.6
Mar	316	69.1%	4.8%	$0.0	141	30.9%	27.9%	$0.8
Apr	257	65.2%	16.9%	$0.0	137	34.8%	40.3%	$0.8
May	579	70.2%	15.2%	$0.1	246	29.8%	45.2%	$1.7
Jun	1,210	71.2%	22.8%	$0.1	489	28.8%	32.6%	$4.4
Jul	3,255	77.2%	19.2%	$0.2	962	22.8%	36.4%	$7.7
Aug	1,750	70.6%	26.1%	$0.3	727	29.4%	38.0%	$7.1
Sep	1,015	74.6%	24.0%	$0.1	345	25.4%	38.0%	$2.7
Oct	1,030	66.5%	33.3%	$0.0	520	33.5%	62.1%	$6.2
Nov	611	63.3%	33.0%	$0.1	354	36.7%	75.2%	$7.4
Dec	262	29.6%	32.2%	$0.0	622	70.4%	69.4%	$11.3
Total	10,888	69.4%	22.0%	$0.9	4,805	30.6%	46.5%	$52.1

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two different scenarios.[18] The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

Table 4-9 shows monthly day-ahead and real-time LOC credits in 2020 and 2021. In 2021, LOC credits increased by $11.0 million or 56.8 percent compared to 2020, comprising of a $10.6 million increase in day-ahead LOC and a $0.4 million increase in real-time LOC.

In 2021, wind units received $0.2 million of real-time LOC, up by 9.0 percent from 2020. In 2021, real-time LOC credits to wind units were 56.7 percent of the uplift payments to wind units. Wind units in the AEP and COMED

18 Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

Zones received 98.5 percent of real-time LOC credits to wind units. Wind units are not required to procure CIRs equal to the maximum facility output, but are paid uplift when PJM requests that the units reduce output below the maximum facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should be based on the lowest of the desired output, the estimated output based on actual wind conditions, or the capacity interconnection rights (CIRs).

Table 4-9 Monthly lost opportunity cost credits (Millions): 2020 and 2021

	2020			2021		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.5	$0.0	$0.5	$0.4	$0.0	$0.4
Feb	$0.4	$0.0	$0.4	$0.5	$0.0	$0.6
Mar	$0.6	$0.1	$0.6	$3.5	$0.0	$3.5
Apr	$0.3	$0.5	$0.9	$0.6	$0.0	$0.6
May	$0.8	$0.0	$0.8	$2.8	$0.1	$2.9
Jun	$3.3	$0.1	$3.4	$3.0	$0.1	$3.1
Jul	$4.2	$0.1	$4.2	$1.8	$0.1	$1.8
Aug	$4.4	$0.1	$4.5	$1.5	$0.1	$1.6
Sep	$1.6	$0.0	$1.7	$2.5	$0.5	$3.0
Oct	$0.9	$0.0	$0.9	$2.2	$0.2	$2.4
Nov	$0.8	$0.0	$0.8	$6.7	$0.5	$7.2
Dec	$0.4	$0.2	$0.6	$3.2	$0.0	$3.2
Total	$18.2	$1.2	$19.3	$28.7	$1.6	$30.3
Share	93.9%	6.1%	100.0%	94.7%	5.3%	100.0%

Table 4-10 shows day-ahead generation for combustion turbines and diesels, including scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and day-ahead generation receiving LOC credits. In 2021, 10.9 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 3.7 percentage points lower than in 2020. In 2021 compared to 2020, day-ahead generation by combustion turbines decreased by 11.8 percent, day-ahead generation not requested in real time decreased by 34.2 percent, and day-ahead generation not requested in real time receiving lost opportunity costs decreased by 55.7 percent. Unlike steam units, combustion turbines that clear the day-ahead energy market have to be instructed by PJM to come online in real time.

Table 4-10 Day-ahead generation from combustion turbines and diesels (GWh): 2020 and 2021

	2020			2021		
	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)
Jan	873	171	73	486	69	17
Feb	653	114	49	507	53	12
Mar	729	103	55	527	64	16
Apr	656	95	36	957	62	15
May	1,126	188	80	1,153	213	55
Jun	2,278	437	243	1,869	223	76
Jul	4,759	588	271	2,179	149	46
Aug	2,728	384	180	2,804	162	32
Sep	1,696	341	129	1,358	131	47
Oct	1,677	155	83	1,811	143	48
Nov	1,051	119	66	2,109	378	144
Dec	641	59	23	888	165	63
Total	18,867	2,754	1,289	16,649	1,811	570
Share	100.0%	14.6%	6.8%	100.0%	10.9%	3.4%

Uplift Eligibility

In PJM, units have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by generation owners. Table 4-11 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[19] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may be self scheduled in the day-ahead market and then be pool scheduled and dispatched in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are defined in the tariff as eligible for balancing operating reserve credits. However, in practice, units receive uplift credits when not following PJM's dispatch signal Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and unable to recover their operating cost for the day or segment.[20]

Table 4-11 Dispatch status, commitment status and uplift eligibility[21]

		Commitment Status	
Dispatch Status	Dispatch Description	Self Scheduled (units committed by the generation owner)	Pool Scheduled and following PJM's dispatch signal (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Only eligible to receive LOC credits if dispatched down by PJM Eligible to set LMP	Eligible to receive uplift Eligible to set LMP

Table 4-12 shows day-ahead and real-time generation by commitment and dispatch status.

Table 4-12 Day-ahead and real-time generation by offer status and eligibility to set LMP (GWh): 2021

	Self Scheduled			Pool Scheduled						Total Generation
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Eligible to Set Price
Day-Ahead Generation	87,063	192,356	177,981	168,649	174,962	21,846	822,857	365,457	457,400	255,712
Share of Day-Ahead	10.6%	23.4%	21.6%	20.5%	21.3%	2.7%	100.0%	44.4%	55.6%	31.1%
Real-Time Generation	76,894	182,971	179,154	168,902	193,632	26,385	827,938	388,919	439,019	245,796
Share of Real-Time	9.3%	22.1%	21.6%	20.4%	23.4%	3.2%	100.0%	47.0%	53.0%	29.7%

Economic and Noneconomic Generation[22]

Economic generation includes units scheduled day ahead by PJM, or that produce energy in real time, at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units scheduled day ahead by PJM, or that produce energy in real time, at an incremental offer greater than the LMP at the unit's bus.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load and startup cost. A unit could be noneconomic

19 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
20 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.
21 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.
22 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

for multiple hours and not receive operating reserve credits when the total revenues covered the total offer (including no load and startup cost) for the entire day or segment.

Table 4-13 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits as defined by PJM. In 2021, 89.5 percent of the day-ahead generation MWh eligible for operating reserve credits was economic and 65.9 percent of the real-time generation MWh eligible for operating reserve credits was economic. A unit's generation MWh may be noneconomic for a portion of their daily generation and economic for the rest.

Table 4-13 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2021

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	327,240	38,217	365,457	89.5%	10.5%
Real-Time	216,543	112,033	328,576	65.9%	34.1%

Noneconomic generation only leads to operating reserve credits when a unit is unable to recover its operating costs for the entire day or segment. Table 4-14 shows the generation receiving day-ahead and balancing operating reserve credits. In 2021, 1.0 percent of the day-ahead generation eligible for operating reserve credits received credits and 2.9 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-14 Generation receiving operating reserve credits (GWh): 2021

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	365,457	3,590	1.0%
Real-Time	328,576	6,363	1.9%

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, such as not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases. Since 2018, the cumulative resettlement requests totaled $14.8 million. Of that amount, PJM has agreed and resettled 9.9 percent of the requests, 84.3 percent remains pending. The remaining 5.8 percent occurred prior to January 2020 and would now require a directive from FERC for them to be resettled. The MMU continues to bring new cases to the attention of PJM.

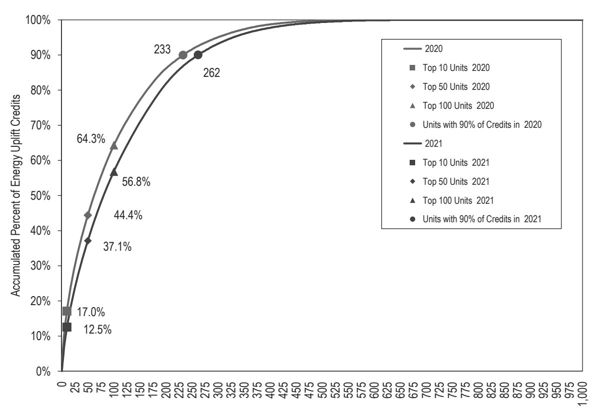
The MMU identifies units that are not following the dispatch signal and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved based on the real-time LMP, unit operating parameters (e.g. economic minimum, maximum and ramp rate) and energy offer.

Concentration of Energy Uplift Credits

The recipients of uplift payments are highly concentrated by unit and by company. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that a lack of full transparency has made it more difficult for competition to affect these payments.[23]

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 13.1 percent of total energy uplift credits in 2021, compared to 17.0 percent in 2020. In 2021, 261 units received 90 percent of all energy uplift credits, compared to 233 units in 2020.

Figure 4-1 Cumulative share of energy uplift credits by unit: 2020 and 2021



23 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits incurred on and after July 1, 2019 on September 10, 2019.

Table 4-15 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in 2021.

Table 4-15 Top 10 units and organizations energy uplift credits: 2021

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$10.0	73.2%	$0.0	0.0%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$16.6	13.0%	$91.3	71.6%
	Local Constraints Control	$4.6	95.2%	$4.8	100.0%
	Lost Opportunity Cost	$5.1	17.0%	$22.6	74.5%
	Dispatch Differential Lost Opportunity Cost	$0.16	22.6%	$0.4	64.7%
Reactive Services		$0.9	94.4%	$0.9	99.9%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	41.6%	$0.3	87.3%
Total		$22.4	12.5%	$120.9	67.8%

Table 4-16 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2021, 69.8 percent of all credits paid to these units were allocated as charges to deviations while the remaining 30.2 percent were paid for reliability reasons.

Table 4-16 Balancing operating reserve credits to top 10 units as charged by category and region: 2021

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$4.4	$0.6	$0.0	$9.9	$1.7	$0.0	$16.6
Share	26.5%	3.7%	0.0%	59.8%	10.0%	0.0%	100.0%

In 2021, concentration in all energy uplift credit categories was high.[24] [25] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category.[26] Table 4-17 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 7876, for balancing operating reserve credits to generators was 2637, for lost opportunity cost credits was 5728 and for reactive services credits was 2770. All of these HHI values are characterized as highly concentrated.

Table 4-17 Daily energy uplift credits HHI: 2021

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	7876	1842	10000	100.0%	42.6%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	100.0%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	2637	684	10000	100.0%	22.6%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	5728	1206	10000	100.0%	18.5%
	Dispatch Differential Lost Opportunity Cost	2770	576	10000	100.0%	15.6%
Reactive Services		9683	5088	10000	100.0%	75.8%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9758	5005	10000	100.0%	17.6%
Total		2770	576	10000	96.1%	20.1%

24 See the *2020 State of the Market Report for PJM*, Volume II, Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
25 Table 4-16 excludes local constraint control categories.
26 Concentration is measured using the entity (or entities) to which the uplift credit is paid.

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-18 through Table 4-21 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits. The top 10 units receiving uplift credits received 12.5 percent of all credits, with the top recipient receiving 1.8 percent. The top 10 units receiving day-ahead operating reserves received 73.2 percent. The top 10 recipients of balancing operating reserves received 13.0 percent of balancing operating reserve credits. The top 10 recipients of lost opportunity cost credits received 17.0 percent of total lost opportunity cost credits.

Table 4-18 Top 10 recipients of total uplift: 2021

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 2 F	BGE	$3,123,920	1.8%
2	VP MARSHRUN 1 CT	DOM	$2,719,508	1.5%
3	VP MARSHRUN 2 CT	DOM	$2,565,030	1.4%
4	VP MARSHRUN 3 CT	DOM	$2,557,802	1.4%
5	VP LOUISA 5 CT	DOM	$2,343,764	1.3%
6	DPL INDIAN RIVER 4 F	DPL	$2,004,671	1.1%
7	BC BRANDON SHORES 1 F	BGE	$1,978,429	1.1%
8	FE LEMOYNE 1 CT	ATSI	$1,827,833	1.0%
9	DAY GREENVILLE 1 CT	DAY	$1,695,954	1.0%
10	DAY GREENVILLE 4 CT	DAY	$1,549,296	0.9%
Total of Top 10			$22,366,207	12.5%
Total Uplift Credits			$178,267,192	100.0%

Table 4-19 Top 10 recipients of day-ahead generation credits: 2021

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	$2,840,819	20.8%
2	BC BRANDON SHORES 1 F	BGE	$1,536,104	11.2%
3	PEP MORGANTOWN 1 F	PEPCO	$1,487,880	10.9%
4	DPL INDIAN RIVER 4 F	DPL	$1,393,021	10.2%
5	PEP MORGANTOWN 2 F	PEPCO	$815,486	6.0%
6	DPL WILDCAT POINT 1 CC	DPL	$500,010	3.7%
7	PL BRUNNER ISLAND 3 F	PPL	$408,378	3.0%
8	PL BRUNNER ISLAND 1 F	PPL	$387,299	2.8%
9	PEP CHALKPOINT 3 F	PEPCO	$352,550	2.6%
10	VP BRUNSWICK 1CC	DOM	$280,850	2.1%
Total of Top 10			$10,002,396	73.2%
Total day-ahead operating reserve credits			$13,662,162	100.0%

Table 4-20 Top 10 recipients of balancing operating reserve credits: 2021

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	VP MARSHRUN 1 CT	DOM	$2,571,776	2.0%
2	VP MARSHRUN 3 CT	DOM	$2,390,266	1.9%
3	VP MARSHRUN 2 CT	DOM	$2,370,595	1.9%
4	VP LOUISA 5 CT	DOM	$2,227,587	1.7%
5	FE LEMOYNE 1 CT	ATSI	$1,361,459	1.1%
6	FE LEMOYNE 2 CT	ATSI	$1,176,797	0.9%
7	AEP ROBERT P MONE 2 CT	AEP	$1,145,841	0.9%
8	AEP ROBERT P MONE 3 CT	AEP	$1,143,296	0.9%
9	FE LEMOYNE 3 CT	ATSI	$1,113,152	0.9%
10	AEP ROBERT P MONE 1 CT	AEP	$1,098,235	0.9%
Total of Top 10			$16,599,004	13.0%
Total balancing operating reserve credits			$127,525,881	100.0%

Table 4-21 Top 10 recipients of lost opportunity cost credits: 2021

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	DPL	$745,783	2.5%
2	DPL COMM CHESAPEAKE - NEW CHURCH 4 CT	DPL	$556,642	1.8%
3	DPL COMM CHESAPEAKE - NEW CHURCH 5 CT	DPL	$501,089	1.7%
4	EKPC BLUEGRASS 1 CT	External	$492,360	1.6%
5	COM 900 ELWOOD 6 CT	COMED	$487,729	1.6%
6	VP DOSWELL 3 CT	DOM	$483,384	1.6%
7	VP REMINGTON 4 CT	DOM	$473,966	1.6%
8	VP FOUR RIVERS 1 CT	DOM	$471,837	1.6%
9	VP REMINGTON 1 CT	DOM	$467,465	1.5%
10	FE LEMOYNE 1 CT	ATSI	$462,919	1.5%
Total of Top 10			$5,143,175	17.0%
Total lost opportunity cost credits			$30,327,914	100.0%

Table 4-22 Top 10 recipients of dispatch differential lost opportunity cost credits: 2021

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	AP LKLYN 1-4 H	AP	$57,072	8.2%
2	VP DOSWELL 2 CT	DOM	$13,447	1.9%
3	PL HUMMEL STATION 1 CC	PPL	$13,336	1.9%
4	VP DOSWELL 3 CT	DOM	$12,884	1.9%
5	FE LORDSTOWN ENERGY CENTER 1 CC	ATSI	$11,610	1.7%
6	PL SAFEHARBOR 11 H	PPL	$11,223	1.6%
7	PN KEYSTONE 1 F	PE	$10,567	1.5%
8	VP FOUR RIVERS 60 CC	DOM	$9,532	1.4%
9	VP FOUR RIVERS 50 CC	DOM	$8,518	1.2%
10	VP FLUVANNA CC	DOM	$8,445	1.2%
Total of Top 10			$156,635	22.6%
Total dispatch differential lost opportunity cost credits			$694,605.1	2.3%

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-23 and Table 4-24 show the categories of credits and charges and their relationship. These tables show how the charges are allocated. The dispatch differential lost opportunity cost credit is a new balancing credit that was introduced during the implementation of fast start pricing on September 1, 2021. The new credit is charged and allocated to PJM members in proportion to their real-time load and exports for generator credits provided for reliability.

Table 4-23 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids & UTCs	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids & UTCs	in RTO Region
Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits		→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids & UTCs	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	in RTO, Eastern or Western Region
			Balancing Local Constraint	Applicable Requesting Party	
Dispatch Differential Lost Opportunity Cost (DDLOC)	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Deviations	Real-Time Load plus Real-Time Export Transactions	in RTO Region
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-24 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Charges Results

Energy Uplift Charges

Total energy uplift charges increased by $87.4 million, or 96.2 percent, in 2021 compared to 2020, from $90.9 million to $178.3 million.

Table 4-25 Total energy uplift charges: 2001 through 2021[27]

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.3%)	0.2%
2020	$90.9	($107.3)	(54.1%)	0.2%
2021	$178.3	$87.4	96.2%	0.5%

Table 4-26 shows total energy uplift charges by category in 2020 and 2021.[28] The increase of $87.4 million is comprised of a $4.4 million increase in day-ahead operating reserve charges, an $82.5 million increase in balancing operating reserve charges, a $0.5 million increase in reactive service charges, and a $.1 million increase in black start services charges.

Table 4-26 Total energy uplift charges by category: 2020 and 2021[29]

Category	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$9.3	$13.7	$4.4	47.1%
Balancing Operating Reserves	$80.9	$163.4	$82.5	101.9%
Reactive Services	$0.4	$0.9	$0.5	112.2%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.2	$0.3	$0.1	34.9%
Total	$90.9	$178.3	$87.4	96.2%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.3%	0.1%	31.5%

27 In Table 4-25, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.
28 Table 4-25 includes all categories of charges as defined in Table 4-23 and Table 4-24 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 12, 2022.
29 In Table 4-26, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 4-27 compares monthly energy uplift charges by category for 2020 and 2021.

Table 4-27 Monthly energy uplift charges: 2020 and 2021

	2020 Charges (Millions)						2021 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$0.1	$4.0	$0.0	$0.0	$0.0	$4.1	$0.7	$6.8	$0.7	$0.0	$0.0	$8.2
Feb	$0.2	$1.2	$0.0	$0.0	$0.0	$1.4	$0.9	$13.6	$0.1	$0.0	$0.0	$14.6
Mar	$0.0	$1.6	$0.0	$0.0	$0.0	$1.7	$2.8	$8.5	$0.0	$0.0	$0.1	$11.4
Apr	$0.8	$2.0	$0.1	$0.0	$0.1	$2.9	$0.8	$17.0	$0.0	$0.0	$0.0	$17.8
May	$1.0	$2.7	$0.3	$0.0	$0.0	$4.0	$0.6	$8.7	$0.0	$0.0	$0.0	$9.3
Jun	$0.9	$8.5	$0.0	$0.0	$0.0	$9.5	$1.3	$16.5	$0.0	$0.0	$0.0	$17.8
Jul	$1.2	$13.0	$0.0	$0.0	$0.0	$14.2	$0.6	$19.7	$0.0	$0.0	$0.0	$20.3
Aug	$0.8	$12.6	$0.0	$0.0	$0.0	$13.4	$1.1	$21.2	$0.0	$0.0	$0.0	$22.3
Sep	$2.1	$5.4	$0.0	$0.0	$0.0	$7.5	$1.9	$7.3	$0.0	$0.0	$0.0	$9.2
Oct	$1.1	$8.0	$0.0	$0.0	$0.1	$9.1	$0.4	$14.2	$0.0	$0.0	$0.1	$14.7
Nov	$0.6	$8.8	$0.0	$0.0	$0.0	$9.4	$0.8	$21.6	$0.2	$0.0	$0.0	$22.6
Dec	$0.5	$13.2	$0.0	$0.0	$0.0	$13.7	$1.6	$8.3	$0.0	$0.0	$0.0	$9.9
Total	$9.3	$80.9	$0.4	$0.0	$0.2	$90.9	$13.7	$163.4	$0.9	$0.0	$0.3	$178.3
Share	10.2%	89.1%	0.5%	0.0%	0.3%	100.0%	7.7%	91.7%	0.5%	0.0%	0.2%	100.0%

Table 4-28 shows the composition of day-ahead operating reserve charges. Day-ahead operating reserve charges include payments for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[30] [31] Day-ahead operating reserve charges increased by $4.4 million 47.1 percent in 2021 compared to 2020.

Table 4-28 Day-ahead operating reserve charges: 2020 and 2021

Type	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	2020 Share	2021 Share
Day-Ahead Operating Reserve Charges	$9.3	$13.7	$4.4	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$9.3	$13.7	$4.4	100.0%	100.0%

Table 4-29 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $82.5 million or 101.9 percent in 2021 compared to 2020.

Table 4-29 Balancing operating reserve charges: 2020 and 2021

Type	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	2020 Share	2021 Share
Balancing Operating Reserve Reliability Charges	$27.2	$62.9	$35.7	33.6%	38.5%
Balancing Operating Reserve Deviation Charges	$50.3	$95.7	$45.3	62.2%	58.5%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Balancing Local Constraint Charges	$3.4	$4.8	$1.4	4.2%	3.0%
Total	$80.9	$163.4	$82.5	100.0%	100.0%

30 See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times since 1999, totaling $26.9 million.

31 See the *2021 Quarterly State of the Market Report for PJM: January through June*, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-30 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges are the sum of: make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators, and payments to resources scheduled by PJM but canceled by PJM before coming online. In 2021, energy lost opportunity cost deviation charges increased by $11.0 million or 56.8 percent, and make whole deviation charges increased by $34.3 million or 110.7 percent compared to 2020.

Table 4-30 Balancing operating reserve deviation charges: 2020 and 2021

Charge Attributable To	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	2020 Share	2021 Share
Make Whole Payments to Generators and Imports	$31.0	$65.3	$34.3	61.6%	68.3%
Energy Lost Opportunity Cost	$19.3	$30.3	$11.0	38.4%	31.7%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$50.3	$95.7	$45.3	100.0%	100.0%

Table 4-31 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $0.5 million or 47.5 percent in 2021, compared to 2020.

Table 4-31 Additional energy uplift charges: 2020 and 2021

Type	2020 Charges (Millions)	2021 Charges (Millions)	Change (Millions)	2020 Share	2021 Share
Reactive Services Charges	$0.4	$0.9	$0.5	65.0%	47.5%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.2	$0.3	$0.1	35.0%	16.3%
Total	$0.7	$1.9	$1.3	100.0%	100.0%

Table 4-32 and Table 4-33 show the amount and shares of regional balancing charges in 2020 and 2021. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In 2021, the largest share of regional charges was paid by real-time load which paid 37.8 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2021, regional balancing operating reserve charges increased by $81.1 million compared to 2020. Balancing operating reserve reliability charges increased by $35.7 million or 131.5 percent, and balancing operating reserve deviation charges increased by $45.3 million, or 90.0 percent.

Table 4-32 Regional balancing charges allocation (Millions): 2020

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$22.0	28.4%	$3.5	4.6%	$0.3	0.3%	$25.8	33.3%
	Real-Time Exports	$1.2	1.5%	$0.1	0.2%	$0.0	0.0%	$1.3	1.7%
	Total	$23.2	29.9%	$3.7	4.8%	$0.3	0.4%	$27.2	35.1%
Deviation Charges	Demand	$31.2	40.3%	$2.7	3.4%	$0.3	0.4%	$34.2	44.2%
	Supply	$5.7	7.3%	$0.5	0.7%	$0.1	0.1%	$6.3	8.1%
	Generator	$9.0	11.6%	$0.7	1.0%	$0.1	0.1%	$9.9	12.7%
	Total	$45.9	59.2%	$3.9	5.1%	$0.5	0.6%	$50.3	64.9%
Total Regional Balancing Charges		$69.1	89.2%	$7.6	9.8%	$0.8	1.0%	$77.5	100%

Table 4-33 Regional balancing charges allocation (Millions): 2021

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$54.6	34.4%	$4.7	3.0%	$0.6	0.4%	$59.9	37.8%
	Real-Time Exports	$2.7	1.7%	$0.2	0.1%	$0.0	0.0%	$3.0	1.9%
	Total	$57.3	36.2%	$4.9	3.1%	$0.6	0.4%	$62.9	39.7%
Deviation Charges	Demand	$64.1	40.4%	$4.2	2.6%	$0.7	0.5%	$69.0	43.5%
	Supply	$8.9	5.6%	$0.7	0.4%	$0.1	0.1%	$9.7	6.1%
	Generator	$15.8	9.9%	$1.1	0.7%	$0.1	0.1%	$17.0	10.7%
	Total	$88.7	55.9%	$6.0	3.8%	$1.0	0.6%	$95.7	60.3%
Total Regional Balancing Charges		$146.0	92.1%	$10.9	6.9%	$1.6	1.0%	$158.6	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. Table 4-34 shows how these charges are allocated.[32]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2020 and 2021. The average rate in 2021 was $0.016 per MWh, $0.004 per MWh higher than the average in 2020. The highest rate in 2021 occurred on August 26, when units were called on by PJM for transmission constraints, and the rate reached $0.210 per MWh, $0.045 per MWh higher than the $0.164 per MWh reached in 2020, on April 6. Figure 4-2 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in 2020 through 2021.

Figure 4-2 Daily day-ahead operating reserve rate ($/MWh): 2020 and 2021

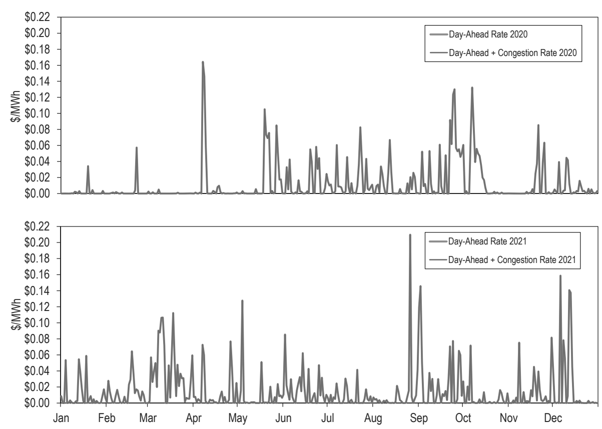


Figure 4-3 shows the RTO and the regional reliability rates for 2020 and 2021. The average RTO reliability rate in 2021 increased to $0.071 per MWh from $0.030 in 2020, indicating a higher need for uplift credits for reliability in 2021. The highest RTO reliability rate in 2021 occurred on June 29 when the rate reached $0.661 per MWh, $0.205 per MWh higher than the $0.457 per MWh rate reached in 2020, on November 19.

32 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost and the canceled resources rates to the deviation rate for the RTO Region since these three charges are allocated following the same rules.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): 2020 and 2021

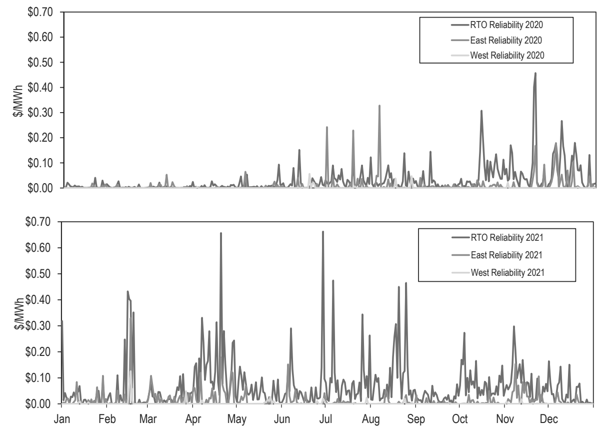


Figure 4-4 shows the RTO and regional deviation rates for 2020 and 2021. The average RTO deviation rate in 2021 was $0.268 per MWh. The highest daily rate in 2021 occurred on August 18, when the RTO deviation rate reached $2.417 per MWh, $1.195 per MWh more than the $1.222 per MWh rate reached in 2020, on August 20.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): 2020 and 2021

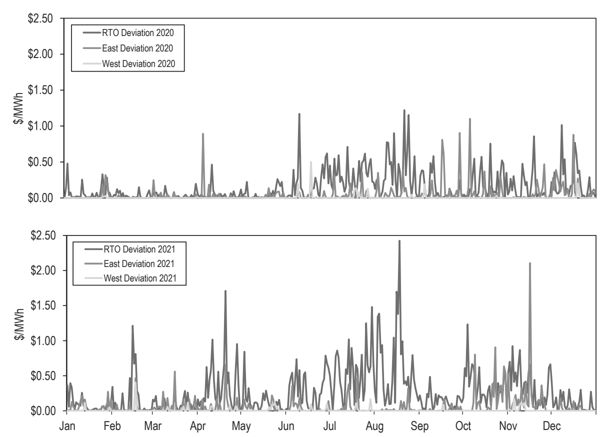


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2020 and 2021. The average lost opportunity cost rate in 2020 was $0.139 per MWh. The highest lost opportunity cost rate in 2021 occurred on December 8, when it reached $1.936 per MWh, $0.013 per MWh greater than the $1.923 per MWh rate reached in 2020, on June 2.

Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): 2020 and 2021

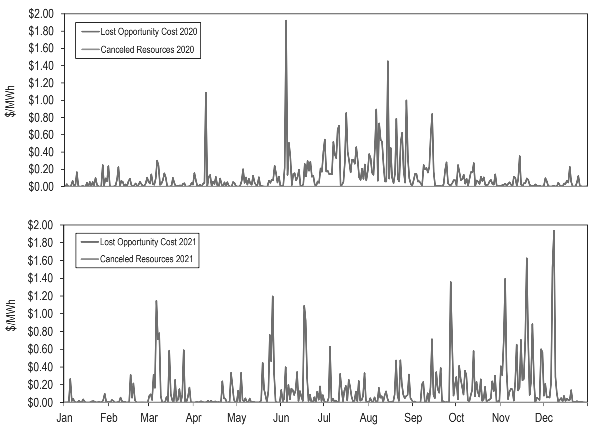


Table 4-34 shows the average rates for each region in each category for 2020 and 2021.

Table 4-34 Operating reserve rates ($/MWh): 2020 and 2021

Rate	2020 ($/MWh)	2021 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.012	0.016	0.004	35.8%
Day-Ahead with Unallocated Congestion	0.012	0.016	0.004	35.8%
RTO Reliability	0.030	0.071	0.042	140.6%
East Reliability	0.010	0.013	0.003	27.5%
West Reliability	0.001	0.002	0.001	129.8%
RTO Deviation	0.161	0.268	0.107	66.3%
East Deviation	0.050	0.060	0.010	19.7%
West Deviation	0.006	0.009	0.003	52.6%
Lost Opportunity Cost	0.117	0.139	0.022	18.8%
Canceled Resources	0.000	0.000	NA	N/A
Dispatch Differential Lost Opportunity Cost	NA	0.001	NA	N/A

Table 4-35 shows the operating reserve cost of a one MW transaction in 2021. For example, in the Eastern Region an increment offer resulting in a one MW deviation or a one MW load deviation paid an average rate of $0.467 per MWh. The rates in Table 4-35 include all operating reserve charges including RTO deviation charges. The rates also include charges for UTCs, which were implemented on November 1, 2020 and which are treated identically to DECs. Table 4-35 includes both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-35 Operating reserve rates statistics ($/MWh): 2021

Region	Transaction	Rates Charged ($/MWh) Maximum	Average	Minimum	Standard Deviation
East	INC	3.012	0.467	<0.001	0.476
	DEC	3.029	0.482	<0.001	0.476
	DA Load	0.210	0.016	<0.001	0.028
	RT Load	0.835	0.084	<0.001	0.106
	Deviation	3.012	0.467	<0.001	0.476
West	INC	2.434	0.416	<0.001	0.429
	DEC	2.449	0.431	<0.001	0.430
	DA Load	0.210	0.016	<0.001	0.028
	RT Load	0.682	0.073	<0.001	0.095
	Deviation	2.434	0.416	<0.001	0.429

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments if they are committed out of merit to provide reactive, or incur opportunity costs associated with reduced energy output. These charges are separate from the reactive service capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[33] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-36 shows the reactive services rates associated with local voltage support in 2020 and 2021. Table 4-36 shows that in 2021 only three zones incurred reactive services charges, in addition to reactive capability charges. Real-time load in the PPL Zone, where reactive service charges were the highest, paid an average of $0.017 per MWh for reactive services. Reactive service charges were second highest in the COMED Zone, where the average rate was $0.002 per MWh.

33 See *2021 State of the Market Report for PJM*, Volume 2; Section 10: Ancillary Service Markets.

Table 4-36 Local voltage support rates: 2020 and 2021

Control Zone	2020 ($/MWh)	2021 ($/MWh)	Difference ($/MWh)	Percent Difference
ACEC	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	0.000	731.1%
APS	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.000	0.000	0.0%
COMED	0.000	0.002	0.002	NA
DAY	0.000	0.000	0.000	0.0%
DUKE	0.000	0.000	0.000	0.0%
DUQ	0.000	0.000	0.000	0.0%
DOM	0.000	0.000	0.000	0.0%
DPL	0.000	0.000	(0.000)	(89.8%)
EKPC	0.004	0.000	(0.004)	(97.4%)
JCPLC	0.008	0.000	(0.008)	(100.0%)
MEC	0.000	0.000	0.000	58.7%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PE	0.000	0.000	0.000	0.0%
PEPCO	0.000	0.000	0.000	0.0%
PPL	0.004	0.017	0.013	290.8%
PSEG	0.000	0.000	0.000	0.0%
REC	0.000	0.000	0.000	0.0%

Balancing Operating Reserve Determinants

Table 4-37 shows the determinants used to allocate the regional balancing operating reserve charges in 2020 and 2021. Total real-time load and real-time exports were 803,908 GWh, 2.7 percent higher in 2021 compared to 2020. Total deviations summed across the demand, supply, and generator categories were 217,861 GWh, 32.0 percent higher in 2021 compared to 2020.

Table 4-37 Balancing operating reserve determinants (GWh): 2020 and 2021

		Reliability Charge Determinants (GWh)			Deviation Charge Determinants (GWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
2020	RTO	742,987	39,888	782,875	110,104	22,539	32,369	165,012
	East	355,089	13,276	368,364	51,472	12,132	15,275	78,879
	West	387,898	26,612	414,510	57,946	10,101	17,094	85,141
2021	RTO	767,425	36,483	803,908	158,278	21,997	37,585	217,861
	East	368,851	16,165	385,016	71,314	10,687	18,194	100,194
	West	398,574	20,318	418,892	84,516	11,039	19,391	114,946
Difference	RTO	24,438	(3,405)	21,033	48,174	(541)	5,216	52,849
	East	13,763	2,889	16,652	19,842	(1,446)	2,919	21,315
	West	10,676	(6,294)	4,381	26,569	938	2,298	29,806

Under PJM's operating reserve rules, balancing operating reserve charges are allocated regionally. PJM defined the Eastern and Western regions, in addition to the RTO region to allocate the cost of balancing operating reserves. These regions consist of three location types: zones, hubs/aggregates, and interfaces. The deviations, calculated between day-ahead and real-time generation, are aggregated regionally by location type, depending on where the charge occurs.

Credits paid to generators that are defined as operating for reliability purposes are charged to real-time load and exports. Credits paid to generators and credits paid to import transactions, such as energy lost opportunity credits and cancellation credits, are charged to deviations

Deviations fall into three categories: demand, supply and generator deviations. Table 4-38 shows the different categories by type of transactions that incurred deviations. In 2021, 49.4 percent of all RTO deviations were incurred by virtual transactions, or by a transaction that combines virtuals with exports or load. In 2021, 97.6 percent of transactions including an INC were exclusively INCs and were not combined with any other supply transactions such as imports. In 2021, 98.8 percent of transactions including a DEC were exclusively DECs and were not combined with any other demand transactions such as UTCs, exports, or load. In 2021, 95.7 percent of transactions including a UTC were exclusively UTCs and were not combined with any other demand transactions such as DECs, exports, or load. In 2021, 11.7 percent of day-ahead operating reserve charges were paid by virtuals (DECs and UTCs). In 2021, 28.5 percent of balancing operating reserve charges were paid by virtuals (DECs, UTCs, and INCs). In 2021, UTCs paid 14.1 percent of total uplift charges, DECs paid 6.1 percent of total uplift charges, and INCs paid 5.8 percent of total uplift charges.

Table 4-38 Deviations by transaction type: 2021

Deviation Category	Transaction	Deviation (GWh) RTO	East	West	Share RTO	East	West
Demand	DECs Only	24,448	13,292	10,675	11.2%	13.3%	9.3%
	UTCs Only	61,494	22,440	37,087	28.2%	22.4%	32.3%
	Load Only	62,878	32,059	30,819	28.9%	32.0%	26.8%
	Exports Only	6,612	2,776	3,836	3.0%	2.8%	3.3%
	Combination of Load or Exports without DECs & UTCs	2,841	742	2,099	1.3%	0.7%	1.8%
	Combination of Load or Exports with DECs & UTCs	5	5	0	0.0%	0.0%	0.0%
Supply	INCs Only	18,435	7,989	10,175	8.5%	8.0%	8.9%
	Combination of Imports & INCs	459	425	34	0.2%	0.4%	0.0%
	Imports Only	3,103	2,273	830	1.4%	2.3%	0.7%
Generators		37,585	18,194	19,391	17.3%	18.2%	16.9%
Total		217,861	100,194	114,946	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-39 shows the geography of charges and credits in 2021. Table 4-39 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the PPL Control Zone paid 5.0 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 2.1 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 10.2 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 3.9 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 4.7 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 2.7 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-39 also shows that 88.9 percent of all charges were allocated in control zones, 4.3 percent in hubs and aggregates and 6.7 percent in interfaces.

Table 4-39 Geography of regional charges and credits: 2021

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	ACEC	$2.7	$1.7	($1.0)	1.6%	1.0%	2.0%	0.0%
	AEP	$25.5	$24.9	($0.5)	14.7%	14.5%	1.1%	0.0%
	APS	$7.9	$4.6	($3.3)	4.6%	2.7%	6.7%	0.0%
	ATSI	$10.8	$10.9	$0.1	6.2%	6.3%	0.0%	0.2%
	BGE	$6.8	$8.1	$1.4	3.9%	4.7%	0.0%	2.7%
	COMED	$18.1	$36.1	$18.0	10.5%	20.9%	0.0%	35.2%
	DAY	$3.2	$5.3	$2.1	1.9%	3.1%	0.0%	4.0%
	DUKE	$5.2	$3.2	($2.0)	3.0%	1.9%	3.9%	0.0%
	DUQ	$2.5	$0.1	($2.3)	1.4%	0.1%	4.6%	0.0%
	DOM	$20.1	$32.2	$12.1	11.6%	18.7%	0.0%	23.8%
	DPL	$4.2	$11.1	$6.9	2.4%	6.4%	0.0%	13.5%
	EKPC	$3.1	$7.5	$4.4	1.8%	4.4%	0.0%	8.7%
	External	$0.0	$6.1	$6.1	0.0%	3.5%	0.0%	11.9%
	JCPLC	$4.0	$1.9	($2.2)	2.3%	1.1%	4.3%	0.0%
	MEC	$3.4	$2.1	($1.3)	2.0%	1.2%	2.7%	0.0%
	OVEC	$0.5	$0.0	($0.5)	0.3%	0.0%	1.0%	0.0%
	PECO	$7.2	$1.4	($5.8)	4.1%	0.8%	11.6%	0.0%
	PE	$4.5	$3.5	($1.0)	2.6%	2.0%	2.0%	0.0%
	PEPCO	$5.8	$4.9	($0.9)	3.3%	2.8%	1.8%	0.0%
	PPL	$8.6	$3.6	($5.1)	5.0%	2.1%	10.2%	0.0%
	PSEG	$8.5	$3.2	($5.4)	4.9%	1.8%	10.7%	0.0%
	REC	$1.2	$0.0	($1.2)	0.7%	0.0%	2.3%	0.0%
	All Zones	$153.7	$172.2	$18.5	88.9%	100.0%	65.1%	100.0%
Hubs and Aggregates	AEP - Dayton	$2.0	$0.0	($2.0)	1.1%	0.0%	3.9%	0.0%
	Dominion	$1.2	$0.0	($1.2)	0.7%	0.0%	2.4%	0.0%
	Eastern	$0.5	$0.0	($0.5)	0.3%	0.0%	1.0%	0.0%
	New Jersey	$0.6	$0.0	($0.6)	0.4%	0.0%	1.2%	0.0%
	Ohio	$0.8	$0.0	($0.8)	0.4%	0.0%	1.5%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$2.5	$0.0	($2.5)	1.4%	0.0%	5.0%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$7.5	$0.0	($7.5)	4.3%	0.0%	15.0%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$1.0	$0.0	($1.0)	0.6%	0.0%	1.9%	0.0%
	IMO	$0.4	$0.0	($0.4)	0.2%	0.0%	0.8%	0.0%
	Linden	$0.6	$0.0	($0.6)	0.3%	0.0%	1.1%	0.0%
	MISO	$4.9	$0.0	($4.9)	2.8%	0.0%	9.8%	0.0%
	NCMPA Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Neptune	$0.4	$0.0	($0.4)	0.2%	0.0%	0.8%	0.0%
	NIPSCO	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	NYIS	$1.8	$0.0	($1.8)	1.0%	0.0%	3.6%	0.0%
	South Exp	$0.6	$0.0	($0.6)	0.3%	0.0%	1.2%	0.0%
	South Imp	$0.3	$0.0	($0.3)	0.2%	0.0%	0.6%	0.0%
	South	$1.7	$0.0	($1.7)	1.0%	0.0%	3.5%	0.0%
	All Interfaces	$11.7	$0.0	($11.7)	6.7%	0.0%	19.9%	0.0%
	Total	$172.9	$172.2	($0.7)	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[34] The use of intraday segments to calculate the need for uplift payments results in higher uplift payments than necessary to make units whole, including uplift payments to units that are profitable on a daily basis. The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.

Table 4-40 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In 2021, balancing operating reserve credits would have been $27.0 million or 21.2 percent lower if they were calculated on a daily basis. In 2020, balancing operating reserve credits would have been $10.7 million or 18.5 percent lower if they were calculated on a daily basis.

Table 4-40 Intraday segments and daily balancing operating reserve credits: 2020 and 2021

	2020 BOR Credits (Millions)			2021 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$1.6	$1.3	($0.3)	$4.8	$4.2	($0.5)
Feb	$0.7	$0.5	($0.2)	$10.5	$9.4	($1.2)
Mar	$0.9	$0.7	($0.2)	$5.0	$4.0	($1.0)
Apr	$1.1	$0.9	($0.2)	$16.4	$15.0	($1.3)
May	$1.9	$1.6	($0.3)	$5.8	$4.7	($1.1)
Jun	$5.1	$4.1	($1.0)	$13.0	$9.8	($3.2)
Jul	$8.8	$5.7	($3.0)	$17.8	$14.0	($3.8)
Aug	$8.1	$6.0	($2.1)	$19.6	$14.5	($5.1)
Sep	$3.7	$2.8	($0.9)	$4.2	$2.4	($1.8)
Oct	$6.8	$5.9	($0.9)	$11.6	$8.7	($2.9)
Nov	$7.8	$7.0	($0.8)	$14.0	$9.9	($4.1)
Dec	$11.8	$11.0	($0.9)	$4.9	$4.0	($0.9)
Total	$58.2	$47.4	($10.7)	$127.5	$100.5	($27.0)

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted within the hour. Table 4-41 shows the impact on day-ahead LOC credits to CTs that are committed DA but not RT. The table shows the LOC credits calculated in three ways: with the five minute settlement calculations implemented in April 2018; with hourly settlements prior to the change in April 2018; and with daily settlements. In 2021, LOC credits would have been $2.9 million or 10.2 percent lower if they had been settled on an hourly basis rather than on a five minute basis. In 2021, LOC credits would have been $7.2 million or 25.2 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute basis.

34 See PJM "Manual 28: Operating Reserve Accounting," Rev. 85 (Sep. 1, 2021).

Table 4-41 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: 2021

2021 Day-Ahead LOC Credits (Millions)					
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$0.4	$0.3	($0.1)	$0.2	($0.1)
Feb	$0.5	$0.5	($0.1)	$0.4	($0.2)
Mar	$3.5	$3.1	($0.4)	$2.3	($1.2)
Apr	$0.6	$0.6	$0.0	$0.5	($0.1)
May	$2.8	$2.5	($0.3)	$2.3	($0.5)
Jun	$3.0	$2.8	($0.2)	$2.4	($0.6)
Jul	$1.8	$1.6	($0.2)	$1.4	($0.3)
Aug	$1.5	$1.3	($0.2)	$1.1	($0.4)
Sep	$2.5	$2.3	($0.2)	$2.0	($0.5)
Oct	$2.2	$2.0	($0.2)	$1.7	($0.5)
Nov	$6.7	$6.0	($0.7)	$4.9	($1.8)
Dec	$3.2	$2.9	($0.4)	$2.4	($0.8)
Total	$28.7	$25.8	($2.9)	$21.5	($7.2)

Uplift Credits and Offer Capping

Absent market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[35] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power. Offer capping is designed to set offers at competitive levels.

Table 4-42 shows the uplift credits paid to units that were committed and dispatched on cost offers in 2021. Units received $95.3 million or 74.7 percent of balancing operating reserve credits and $9.4 million or 69.0 percent of day-ahead operating reserve credits in 2021 using price-based offers. Units received $19.1 million or 15.0 percent of balancing operating reserves and $3.7 million or 26.9 percent of day-ahead operating reserves in 2021 using cost-based offers.

Table 4-42 Operating Reserve Credits by Offer Type: 2021

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Operating Reserve Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)	Total
Cost	$3.7	$19.1	$0.3	$0.6	$23.7
Price	$9.4	$95.3	$0.0	$0.0	$104.7
Price PLS	$0.6	$9.7	$0.0	$0.0	$10.3
Cost & Price	$0.0	$3.0	$0.0	$0.0	$3.0
Cost & PLS	$0.0	$0.3	$0.0	$0.0	$0.3
Price & PLS	$0.0	$0.0	$0.0	$0.0	$0.0
Total	$13.7	$127.5	$0.3	$0.6	$142.0
Share	9.6%	89.8%	0.2%	0.4%	100.0%

35 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 4-43 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. Of all the day-ahead credits received during days with weather alerts, 32.2 percent went to units that were committed on price schedules less flexible than PLS.

Table 4-43 Day-ahead operating reserve credits during weather alerts by commitment schedule: 2021

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during Hot and Cold Weather Alerts
Committed on cost (cost capped)	$24,689	2.8%
Committed on price schedule as flexible as PLS	$2,435	0.3%
Committed on price schedule less flexible than PLS	$280,201	32.2%
Committed on price PLS	$562,012	64.6%
Total	$869,337	100.0%

Fast Start Pricing

The implementation of fast start pricing on September 1, 2021, included a new credit intended to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. With fast start pricing, cleared and dispatched MW are determined in the dispatch run, identical to the combined dispatch and pricing process prior to fast start, while LMPs are determined in the pricing run, which calculates prices based on the counterfactual assumption that the fast start resources are flexible and can back down to a low economic minimum MW. Fast start pricing creates a divergence between the pricing run LMP that signals a higher MW for some resources and the lower dispatch run MW to which PJM dispatches the resource based on its offer curve. The resources dispatched down would produce more MWh if they responded to the actual market LMP from the pricing run. The resulting dispatch differential lost opportunity cost credit is the revenue lost by the resource as a result of operating at the lower dispatch MW rather than the MW on its offer curve corresponding to the actual market LMP from the pricing run. Table 4-1 shows that the dispatch differential lost opportunity cost for the first four months of the implementation of fast start pricing was $0.7 million. Table 4-3 shows that 30.8 percent of the dispatch differential lost opportunity cost credit was paid to combined cycle units and 35.8 percent to combustion turbines. In some cases, PJM paid dispatch differential payments to resources that did not follow PJM dispatch instructions. PJM should not make these payments as they are directly counter to the logic of fast start pricing as well as to tariff rules.

The MMU recommends that PJM not make such payments and require refunds where it has already done so. This is part of the broader recommendation that PJM stop paying uplift to resources that do not follow dispatch.

A primary argument made by the proponents of fast start pricing is that it will reduce uplift to fast start units by raising LMP, and thus revenue, when they are operating. This reduction in uplift would be most likely to occur in balancing operating reserves payments. To the extent that fast start pricing increases day-ahead prices, it may also reduce day-ahead operating reserve payments. But fast start pricing also increases other uplift payments, especially the new dispatch differential lost opportunity cost payment. Day-ahead lost opportunity cost payments to fast start resources may also increase because real-time LMPs are higher than they would be without fast start pricing.

There is not enough data on the implementation of fast start pricing after one month to support clear conclusions about the separable impacts of fast start pricing on uplift.

Table 4-44 shows the amount of uplift paid to fast start units by major uplift category. Fast start units received $29.8 million in balancing operating reserve credits, or 23.4 percent of total balancing operating reserves. Fast start units received $5.7 million in day-ahead lost opportunity costs, or 19.8 percent of all lost opportunity costs. Fast start units received $0.1 million in day-ahead operating credits, or 0.9 percent of total day-ahead operating reserve credits.

Table 4-44 Monthly day-ahead operating reserves, balancing operating reserves, and day-ahead lost opportunity cost credits for fast start units: 2021

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Operating Reserves	Share of Monthly Balancing Operating Reserves	Day Ahead Lost Opportunity Cost Credits	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	1.5%	$2.0	42.1%	$0.2	42.4%
Feb	$0.0	3.1%	$2.2	20.8%	$0.2	40.7%
Mar	$0.1	8.4%	$1.7	35.1%	$1.7	47.3%
Apr	$0.0	0.2%	$3.7	22.4%	$0.0	4.9%
May	$0.0	0.5%	$1.5	26.0%	$0.3	9.1%
Jun	$0.0	0.6%	$2.8	21.6%	$0.4	14.2%
Jul	$0.0	0.6%	$3.4	19.0%	$0.3	15.8%
Aug	$0.0	0.3%	$3.8	19.4%	$0.3	20.4%
Sep	$0.0	0.5%	$1.2	28.9%	$0.3	12.0%
Oct	$0.0	0.3%	$3.4	29.0%	$0.4	18.7%
Nov	$0.0	1.0%	$2.7	19.2%	$1.3	18.6%
Dec	$0.0	0.0%	$1.5	30.5%	$0.4	12.1%
Total	$0.1	0.9%	$29.8	23.4%	$5.7	34.2%

Table 4-45 shows the day-ahead, balancing operating reserves, and day-ahead lost opportunity cost credits for combustion turbines by month.

Table 4-45 Day ahead operating reserves, balancing operating reserves, day-ahead lost opportunity cost credits for fast start combustion turbines: 2021

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Operating Reserves	Share of Monthly Day Ahead Operating Reserves	Day Ahead Lost Opportunity Cost Credits	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	1.5%	$1.9	40.4%	$0.1	37.9%
Feb	$0.0	2.5%	$2.1	19.9%	$0.2	36.1%
Mar	$0.1	2.2%	$1.7	34.1%	$1.6	46.8%
Apr	$0.0	0.2%	$3.6	21.8%	$0.0	4.6%
May	$0.0	0.4%	$1.5	25.6%	$0.2	8.7%
Jun	$0.0	0.3%	$2.6	20.4%	$0.4	13.8%
Jul	$0.0	0.8%	$3.3	18.6%	$0.3	15.4%
Aug	$0.0	0.2%	$3.7	18.9%	$0.3	17.2%
Sep	$0.0	0.2%	$1.2	28.5%	$0.3	10.9%
Oct	$0.0	0.5%	$3.3	28.6%	$0.4	16.4%
Nov	$0.0	0.9%	$2.6	18.8%	$1.2	17.9%
Dec	$0.0	0.0%	$1.5	29.9%	$0.3	10.8%
Total	$0.1	0.9%	$29.1	22.8%	$5.4	32.4%

Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the 2022/2023 Base Residual Auction.

Table 5-1 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as not competitive in 2022/2023 RPM Base Residual Auction. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the Net CONE times B offer cap under the capacity performance design exceeds the competitive level. In the 2022/2023 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30, and the other strong CP assumptions are also not correct. Under these circumstances, a competitive offer is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions. The Commission recognized this issue and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021. But the 2022/2023 BRA was conducted with the previous default MSOC of Net CONE times B.[4]
- Market performance was evaluated as not competitive based on the 2022/2023 RPM Base Residual Auction. Although structural market power exists in the capacity market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2022/2023 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

4 176 FERC ¶ 61,137 (September 2, 2021).

the inclusion of imports which are not substitutes for internal capacity resources.

- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2021, and for a number of additional reasons, the 2023/2024 Base Residual Auction is delayed and scheduled for June 2022, and first and second incremental auctions for the 2022/2023 through 2026/2027 Delivery Years are canceled if within 10 months of the revised BRA schedule.[5]

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[6]

Under RPM, capacity obligations are annual.[7] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[8] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[9] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[10]

The 2021/2022 RPM Third Incremental Auction and the 2022/2023 RPM Base Residual Auction were conducted in 2021.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[11] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In 2021, RPM installed capacity increased 2,348.4 MW or 1.3 percent, from 184,245.0 MW on January 1, to 186,593.4 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** The sum of cleared MW that did not have a must offer requirement and the cleared MW of DR is 16,823.3 MW, or 100.7 percent of required reserves and 69.0 percent of total reserves. These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.

5 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021).
6 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
7 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
8 See 126 FERC ¶ 61,275 at P 86 (2009).
9 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
10 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
11 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2021, 46.3 percent was gas; 26.0 percent was coal; 17.3 percent was nuclear; 4.7 percent was hydroelectric; 3.0 percent was oil; 1.4 percent was wind; 0.3 percent was solid waste; and 1.0 percent was solar.
- **Market Concentration.** In the 2021/2022 RPM Third Incremental Auction and the 2022/2023 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[12] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[13] [14] [15]
- **Imports and Exports.** Of the 1,558.0 MW of imports in the 2022/2023 RPM Base Residual Auction, 1,558.0 MW cleared. Of the cleared imports, 954.9 MW (61.3 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,115.9 MW for June 1, 2021, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2021/2022 Delivery Year (16,233.9 MW) less purchases of replacement capacity (4,118.0 MW).

Market Conduct

- **2021/2022 RPM Third Incremental Auction.** Of the 481 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).
- **2022/2023 RPM Base Residual Auction.** Of the 1,083 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).

Market Performance

- The 2021/2022 RPM Third Incremental Auction and 2022/2023 RPM Base Residual Auction were conducted in 2021.[16] The weighted average capacity price for the 2020/2021 Delivery Year is $111.07 per MW-day, including all RPM auctions for the 2020/2021 Delivery Year. The weighted average capacity price for the 2021/2022 Delivery Year is $147.33 per MW-day, including all RPM auctions for the 2021/2022 Delivery Year.
- For the 2021/2022 Delivery Year, RPM annual charges to load are $9.4 billion.
- In the 2022/2023 RPM Base Residual Auction, the market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate. PJM has indicated to another plant that RMR service will be required in 2022.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in 2021 was 7.3 percent, an increase from 6.3 percent in 2020.[17]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2021 was 81.7 percent, a decrease from 84.7 percent in 2020.

12 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

13 See OATT Attachment DD § 6.5.

14 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

15 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

16 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

17 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on January 24, 2022. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Recommendations[18]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[19] [20] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. EE should not be part of the capacity market. If EE is not included on the supply side, there is no reason to have an addback mechanism. If EE remains on the supply side, the MMU recommends that the implementation of the EE addback mechanism be modified to ensure that market clearing prices are not affected.[21] (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and storage resources, including hydro. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to prevent the exercise of market power via withholding. (Priority: High. New recommendation. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual

18 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.
19 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
20 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
21 Based on an Issue Charge introduced by the MMU, PJM has updated the EE addback rules effective with the 2023/2024 Delivery Year, to address this issue. "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 51 (Oct. 20, 2021).

flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[22 23] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Adopted 2021.)

- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA, at much lower prices, procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. New recommendation. Status: Not adopted.)

22 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
23 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[24] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[25] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps

24 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).
25 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal resources. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Adopted, 2021.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)

- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that RMR service should be provided under the deactivation avoidable cost rate in Part V, and that the revenue cap under the avoidable cost rate option be eliminated. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets can and do have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2022/2023 BRA compared to a vertical demand curve was significant. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The small level of elasticity incorporated in the RPM demand curve is not adequate to modify this conclusion. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The level of cleared demand resources (8,710.3 MW) is greater than the entire level of excess capacity cleared in the auction (7,660.2 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called.

The market design for capacity leads to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes. The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[26] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were not implemented in the 2022/2023 BRA.[27] [28] The result was that capacity market prices were above the competitive level. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules. But the CP market seller offer cap was based on strong assumptions that are not correct. The CP market seller offer cap was significantly overstated as a result. For units that could profitably provide energy under the Capacity Performance design even without a capacity payment because their expected CP bonus payments exceed their net ACR, based on expected unit specific performance, expected balancing ratio, expected performance assessment intervals (PAI) and expected penalty payments, the competitive, profit maximizing offer was defined to be Net CONE times B, where B is the expected average balancing ratio. This was the default offer cap for such units only under strong, defined assumptions.[29] Those assumptions included: there are expected PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses; the bonus payments equal the penalties; and capacity resources have the ability to costlessly switch between energy only status and capacity resource status.

But those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result. The Capacity Performance paradigm has not worked as anticipated in PJM and is not expected to work, in part because the assumptions are never likely to be correct. In addition, PAI is an endogenous variable. The expected number of PAI is a function of the level of capacity resources which is a function of offers and the resultant clearing prices. The correct definition of a competitive offer is net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties.

The MMU concludes that the results of the 2022/2023 RPM Base Residual Auction were not competitive as a result of economic withholding by resources that used offers that were consistent with the Net CONE times B offer cap but not consistent with competitive offers based on the correctly calculated offer cap. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. A competitive offer in the capacity market is equal to net ACR.[30] That is the way in which most market participants offered in this and prior capacity performance auctions. The ACR values used in this analysis were based on data provided by the participants and were consistent with competitive offers

26 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

27 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019s ("IMM MSOC Complaint").

28 176 FERC ¶ 61,137 (September 2nd Order).

29 For a detailed derivation, see Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).

30 See 174 FERC ¶ 61,212 at P 65 ("March 18th Order").

for the relevant capacity and were consistent with PJM's posted default ACR values for the referenced technology.

The MMU also concludes that market prices were significantly affected by other flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve, the overstatement of the capacity of intermittent resources, the treatment of DR, the MOPR rules, the inclusion of EE, and the EE addback rules.

The MMU also concludes that, although a much smaller issue in the 2022/2023 auction, the rules permitted the exercise of market power without mitigation for seasonal resources through uplift payments for noncompetitive offers, rather than through higher prices.[31] Although the impact was small in the 2022/2023 auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

The recent changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. The MMU had recommended that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources, although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[32] [33] [34] [35] [36] [37] In 2020 and 2021, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 7,828.5 ICAP MW on June 1, 2021, and will have excess reserves of 8,065.8 ICAP MW on June 1, 2022, based on current positions.[38] A majority of capacity investments in PJM were financed by market sources.[39] Of the 42,969.5 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2021/2022 Delivery Years, 31,509.2 MW (73.3 percent) were based on market funding. Of the 6,587.3 MW of additional capacity that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years, 4,924.2 MW (74.8 percent)

31 PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

32 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

33 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

34 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

35 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

36 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

37 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

38 The calculated reserve margin for June 1, 2022, does not account for cleared buy bids that have not been used in replacement capacity transactions.

39 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

Table 5-2 RPM related MMU reports: January 2021 through February 25, 2022

Date	Name
January 29, 2021	Analysis of NJ Zero Emissions Credit(ZEC)Applications https://www.monitoringanalytics.com/reports/Reports/2021/IMM_Public_Report_Analysis_of_NJ_ZEC_Applications_20210129.pdf
February 19, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20210219.pdf
March 4, 2021	Next Steps in Capacity Market Design https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_Capacity_Market_Workshop_Session_2_Next_Steps_in_Capacity_Market_Design_20210304.pdf
March 5, 2021	IMM Comment re New Jersey FRR Docket No. EO20030203 https://www.monitoringanalytics.com/filings/2021/IMM_Comment_Docket_No_EO20030203_20210305.pdf
March 22, 2021	IMM Comments re ELCC Docket No. ER21-278-001 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-278-001_20210322.pdf
March 31, 2021	IMM Answer re Jackson Complaint Docket No. EL21-62, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_Nos_EL21-62_EL21-63_20210331.pdf
April 7, 2021	RPM Capacity Transfer Rights: Education https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_RPM_Capacity_Transfer_Rights_Education_20210407.pdf
April 12, 2021	IMM Commentsr re Jackson Complaint Docket No. EL21-62, et al https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_Nos_EL21-62_EL21-63_20210412.pdf
April 19, 2021	IMM Answer to P3 re MSOC Docket Nos. EL19-47-001, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_et_al_20210419.pdf
April 26, 2021	IMM Comments re Modernizing Electricity Market Design Docket No. AD21-10 https://www.monitoringanalytics.com/filings/2021/IMM_Post_Technical_Conference_Comments_Docket_No_AD21-10_20210426.pdf
April 28, 2021	IMM Brief re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Brief_Docket_No_EL19-47_et_al_20210428.pdf
April 29, 2021	IMM Answer to PJM re ELCC Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_PJM_Docket_No_ER21-278_20210429.pdf
May 18, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 Delivery Year https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_RPM_Must_Offer_Obligations_20210518.pdf
May 19, 2021	IMM Answer to Motion re ELCC Docket No. EL19-100 and ER20-584 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_Motion_Docket_No_EL19-100_20210519.pdf
May 25, 2021	IMM Comments re PJM Capacity Market CRF Docket No. ER21-1844 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1844_20210525.pdf
June 9, 2021	IMM Reply Brief re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Reply_Brief_Docket_No_EL19-47_EL19-63_20210609.pdf
June 15, 2021	IMM Response to Exelon re 10 Year Report Case No. 9271 https://www.monitoringanalytics.com/filings/2021/IMM_Response_to_Exelon_MDPSC_Case_No_%209271_20210615.pdf
June 16, 2021	IMM MOPR Matrix Entries https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MOPR_Matrix_Entries_20210616.pdf
June 22, 2021	IMM Comments re ELCC Docket No. ER21-2043 https://www.monitoringanalytics.com/filings/2021/IMM_Comment_Docket_No_ER21-2043_20210622.pdf
June 25, 2021	IMM Answer to Replies re MSOC Docket No. EL19-47 and EL19-63 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_20210625.pdf
June 28, 2021	Data Submission Window Opening: 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2023-2024_BRA_20210628.pdf
June 30, 2021	IMM MOPR Matrix Entries https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_CIFP_MOPR_MOPR_Matrix_Entries_20210630.pdf
August 11, 2021	EE Addback Issue https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_EE_Addback_Issue_20210811.pdf
August 11, 2021	EE Addback Issue Charge Revised https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_EE_Addback_Issue_Charge_Rev%2020210811.pdf
August 27, 2021	Quadrennial Review Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_Quad_Review_Issues_20210827.pdf
September 2, 2021	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_20210902.pdf
September 13, 2021	Data Submission Window Reopening: 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_2023_2024_Base_Residual_Auction_20210913.pdf
September 17, 2021	IMM Informational Session on MSOC https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_MSOC_Net_ACR_%20Informational_Session_on_MSOC_20210917.pdf
September 22, 2021	IMM Answer to Comments re MOPR Docket No. ER21-2582 https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_Comments_Docket_No_ER21-2582_20210922.pdf
September 23, 2021	Market Seller Offer Cap (MSOC) Information https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_MSOC_ACR_Market_Seller_Offer_Cap_20210923.pdf
September 27, 2021	IMM MOPR Review: PA House Environmental Resources & Energy Committee https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_PA_House_E_and_E_MOPR_Review_20210927.pdf
September 28, 2021	Capacity Market Phase 2 Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MIC_Capacity_Market_Workshop_20210928.pdf
September 29, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_20232024_BRA_Updated.pdf
September 30, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20210930.pdf
October 5, 2021	Data Submission Window Opening for the 2022/2023 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_20222023_Third_Incremental_Auction_20211005.pdf

Table 5-2 RPM related MMU reports: January 2021 through February 25, 2022 (continued)

Date	Name
October 6, 2021	Data Submission Window Opening for the 2022/2023 RPM Third Incremental Auction – Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_%2020222023_Third_Incremental_Auction_20211005-Updated.pdf
October 12, 2021	IMM Motion for Clarification re MSOC Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Motion_for_Clarification_Docket_No_EL19-47_et_al_20211012.pdf
October 20, 2021	IMM Answer to PJM re RGGI Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_Docket_No_EL19-47_et_al_20211020.pdf
October 22, 2021	Capacity Market Phase 2 Issues https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_RASTF_Capacity_Market_Workshop_202101022.pdf
October 22, 2021	IMM Comments re SOO Green Capacity Complaint Docket No. EL21-103 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_EL21-103_20211022.pdf
October 23, 2021	Unit Specific Net Revenue Calculation (Dispatchable Units) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Net_Revenue_Calculation_2023_2024_Base_Residual_Auction_20211023.pdf
October 30, 2021	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_Revised_20211030.pdf
November 1, 2021	IMM Comments and Market Power Analysis re PSEG-Arclight Transaction Docket No. EC21-128 https://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_EC21-128_20211101.pdf
November 5, 2021	Net Revenue Calculation Update 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Unit_Specific_Net_Revenue_Calculation_Dispatchable_Units_20232024_BRA_20211105.pdf
November 12, 2021	Net Revenue Calculation Update 2023/2024 Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Unit_Specific_Review_Dispatchable_Units_Update_2023_2024_BRA_20211112.pdf
November 18, 2021	IMM Motion for Clarification or Waiver re MSOC Deadlines Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Motion_for_Clarification_or_Waiver_Docket_No_EL19-47_20211118.pdf
November 19, 2021	IMM Comments re ArcLight/PSEG Transaction Docket No. EC21-128 https://www.monitoringanalytics.com/filings/2021/IMM_Letter_Merger_Docket_No_EC21-128_20211119.pdf
November 23, 2021	Alternative MSOC Agreement Template https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Alternative_MSOC_Agreement_Template_20211123.docx
November 23, 2021	Alternative Market Seller Offer Caps for the PJM 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Alternative_MSOC_2023-2024_Base_Residual_Auction_20211123.pdf
November 30, 2021	IMM Determinations Posted for the PJM 2022/2023 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2022-2023_Third_Incremental_Auction_20211130.pdf
December 1, 2021	IMM Answer to PJM re MSOC Docket No. EL19-47, et al https://www.monitoringanalytics.com/filings/2021/IMM_Answer_to_PJM_Answer_Docket_No_EL19-47_20211201.pdf
December 1, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_for_the_20232024_RPM_BRA_20211201.pdf
December 3, 2021	Data Submission Window Reopening- 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_%202023-2024_Base_Residual_Auction_Updated_20211203.pdf
December 29, 2021	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20211229.pdf
January 5, 2022	MSOC Issues https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_Issues_20220110.pdf
January 7, 2021	Reactive Power Compensation and the Capacity Market https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RPCTF_Reactive_Power_Compensation_20220107.pdf
January 27, 2021	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_2023-2024_Base_Residual_Auction_Updated_20220127.pdf
February 4, 2022	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_20232024_Base_Residual_Auction_Updated_20220204.pdf
February 11, 2022	2022 Quadrennial Review: IMM Proposals and Results https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_IMM_CONE_CT_CC_Study_20220211.pdf
February 22, 2022	Analysis of the 2022/2023 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf
February 25, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20220225.pdf

Installed Capacity

On January 1, 2021, RPM installed capacity was 184,245.0 MW (Table 5-3).[40] Over the next 12 months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 186,593.4 MW on December 31, 2021, an increase of 2,348.4 MW or 1.3 percent from the January 1 level.[41] [42] The 2,348.4 MW increase was the result of new or reactivated generation (4,809.7 MW), capacity modifications (670.0 MW), an increase in imports (38.5 MW), offset by an increase in exports (154.9 MW), derates (228.9 MW), and deactivations (2,786.0 MW).

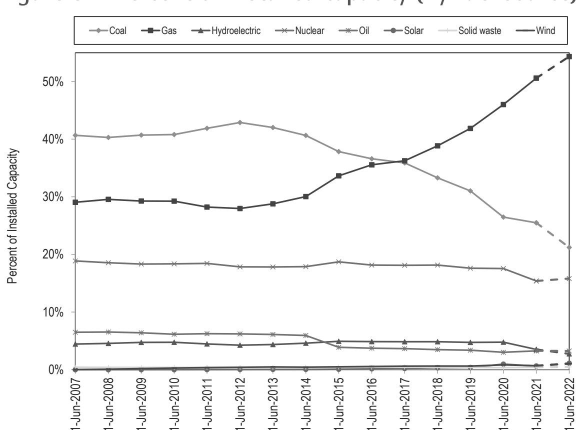
At the beginning of the new delivery year on June 1, 2021, RPM installed capacity was 183,962.3 MW, an increase of 1,024.4 MW or 0.6 percent from the May 31, 2021, level of 182,937.9 MW.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2021

	01-Jan-21		31-May-21		01-Jun-21		31-Dec-21	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	49,747.0	27.0%	49,340.2	27.0%	48,714.4	26.5%	48,568.4	26.0%
Gas	84,031.3	45.6%	83,914.1	45.9%	84,651.7	46.0%	86,321.3	46.3%
Hydroelectric	8,754.3	4.8%	8,753.5	4.8%	8,792.0	4.8%	8,792.0	4.7%
Nuclear	32,312.4	17.5%	32,301.2	17.7%	32,301.2	17.6%	32,301.2	17.3%
Oil	5,512.6	3.0%	5,507.1	3.0%	5,550.1	3.0%	5,545.5	3.0%
Solar	1,014.7	0.6%	1,051.1	0.6%	1,779.5	1.0%	1,824.0	1.0%
Solid waste	695.6	0.4%	650.5	0.4%	650.5	0.4%	650.5	0.3%
Wind	2,177.1	1.2%	1,420.2	0.8%	1,522.9	0.8%	2,590.5	1.4%
Total	184,245.0	100.0%	182,937.9	100.0%	183,962.3	100.0%	186,593.4	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2021, as well as the expected installed capacity for the 2022/2023 Delivery Year, based on the results of all auctions held through September 30, 2021.[43] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 25.5 percent on June 1, 2021, and is projected to decrease to 21.2 percent by June 1, 2022. The share of gas increased from 29.1 percent on June 1, 2007, to 50.6 percent on June 1, 2021, and is projected to increase to 54.3 percent on June 1, 2022.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2022



40 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

41 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.

42 Wind resources accounted for 2,590.5 MW, and solar resources accounted for 1,824.0 MW of installed capacity in PJM on December 31, 2021. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 15 (May 26, 2021). The derating approach will be replaced with ELCC.

43 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2021, through December 31, 2021, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and December 31, 2021[44]

	01-Jan-21			31-May-21			01-Jun-21			31-Dec-21		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	20,843.6	12.2%	1	20,787.3	12.2%	1	20,747.0	12.2%	1	20,801.5	12.1%	1
Dominion Resources, Inc.	19,533.2	11.4%	2	19,505.1	11.5%	2	19,702.1	11.6%	2	19,702.1	11.4%	2
Vistra Energy Corp.	11,319.0	6.6%	3	11,319.0	6.7%	3	11,327.8	6.7%	3	11,327.8	6.6%	3
Riverstone Holdings LLC	10,941.4	6.4%	4	10,866.5	6.4%	5	10,914.8	6.4%	5	10,868.6	6.3%	5
LS Power Group	10,843.7	6.3%	5	11,053.7	6.5%	4	11,253.4	6.6%	4	11,253.4	6.5%	4

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2021, to December 31, 2021, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and December 31, 2021[45]

	01-Jan-21		31-May-21		01-Jun-21		31-Dec-21	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	137,312.5	74.5%	136,106.1	74.4%	136,807.7	74.4%	139,462.8	74.7%
Nonmarket	46,932.5	25.5%	46,831.8	25.6%	47,008.6	25.6%	47,130.6	25.3%
Total	184,245.0	100.0%	182,937.9	100.0%	183,816.3	100.0%	186,593.4	100.0%

Fuel Diversity

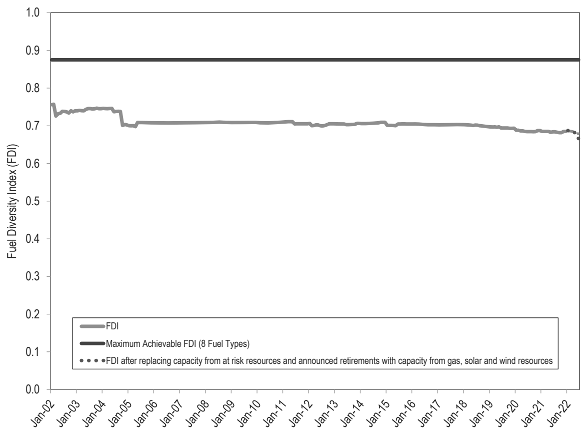
Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[46] The FDI_c is defined as $1 - \sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[47] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[48] The average FDI_c for 2021 decreased 0.3 percent compared to 2020. Figure 5-2 also includes the expected FDI_c through June 2022 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 2,230 MW of capacity were identified as being at risk of retirement.[49] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance of the retirement.[50] There are 7,081.0 MW of generation that have a requested retirement date after December 31, 2021.[51] The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity that cleared in an RPM auction

44 The calculated MW for January 1, 2021, were revised from the *2021 Quarterly State of the Market Report for PJM: January through March.*
45 The calculated MW for January 1, 2021, were revised from the *2021 Quarterly State of the Market Report for PJM: January through March.*
46 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.
47 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.
48 See the *2019 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.
49 See Table 7-47 in the *2021 State of the Market Report for PJM*, Volume II, Section 7: Net Revenue.
50 See OATT Part V § 113.1.
51 See Table 12-11 in the *2021 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning.

from the at risk resources and other resources with deactivation notices is replaced by gas, wind and solar capacity.[52] [53] The FDI_c under these assumptions would decrease by 0.3 percent on average from the expected FDI_c for the period January 1, 2022, through June 1, 2022.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2022



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[54] In 2021, the 2021/2022 RPM Third Incremental Auction and 2022/2023 RPM Base Residual Auction were conducted.[55]

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2020/2021 Delivery Year. The 19,278.5 MW increase was the result of new generation capacity resources (34,017.5 MW), reactivated generation capacity resources (1,374.4 MW), uprates (7,577.6 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (2,016.8 MW), offset by a net decrease in capacity imports (1,051.5 MW), deactivations (42,972.0 MW) and derates (3,651.8 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2018, through June 1, 2022, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2022, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Future Changes in Generation Capacity[56]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2020/2021

52 It is assumed that 1,458.4 MW of replacement capacity is from solar units and 133.7 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 7,669.5 GWh of generation over a one year period assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-27 and Table 8-30. This level of GWh represents the increase in renewable generation required by RPS in 2022 over the level of renewable generation that was required by RPS in2021. The split between solar and wind is based on queue data.

53 For this analysis resources for which PJM has received deactivation notifications were replaced with capacity beginning on the projected retirement date listed in the deactivation data. At risk resources that have not notified PJM regarding deactivation were replaced with capacity beginning on July 1, 2021.

54 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

55 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

56 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Delivery Year, internal installed capacity decreased by 3,654.3 MW after accounting for new capacity resources, reactivations, and uprates (42,969.5 MW) and capacity deactivations and derates (46,623.8 MW).

For the current and future delivery years (2021/2022 through 2022/2023), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified delivery year. Based on expected completion rates of cleared new generation capacity (5,389.5 MW) and pending deactivations (6,911.4 MW), PJM capacity is expected to decrease by 1,521.9 MW for the 2021/2022 through 2022/2023 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 through 2020/2021[57]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
Total	34,017.5	1,374.4	7,577.6	21,967.5	(1,051.5)	(2,016.8)	42,972.0	3,651.8	19,278.5

As shown in Table 5-7, total reserves on June 1, 2022, will be 24,373.5 MW, of which 7,660.2 MW are in excess of the required level of reserves, which is 16,713.3 MW. In the 2022/2023 BRA, 14,918.8 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 2,521.9 MW of intermittent and storage resources (1.7 percent of total cleared MW) were not offered in the 2022/2023 BRA.

The sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,113.0 MW, or 48.5 percent of the required reserves and 33.3 percent of total reserves. The cleared MW of DR is 8,710.3 MW, or 52.1 percent of required reserves and 35.7 percent of total reserves. The sum of cleared MW that did not have a must offer requirement and the cleared MW of DR is 16,823.3 MW, or 100.7 percent of required reserves and 69.0 percent of total reserves.

These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.

57 The capacity changes in this report are calculated based on June 1 through May 31.

Table 5-7 RPM reserve margin: June 1, 2018, to June 1, 2022[58 59]

	01-Jun-18	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	
Forecast peak load ICAP (MW)	152,407.9	151,643.5	148,355.3	149,482.9	150,229.0	A
FRR peak load ICAP (MW)	12,732.9	12,284.2	11,488.3	11,717.7	28,535.5	B
PRD ICAP (MW)	0.0	0.0	558.0	510.0	230.0	C
Installed reserve margin (IRM)	16.1%	16.0%	15.5%	14.7%	14.5%	D
Pool wide average EFORd	6.07%	6.08%	5.78%	5.22%	5.08%	E
Forecast pool requirement (FPR)	1.091	1.090	1.088	1.087	1.087	F=(1+D)*(1-E)
RPM committed less deficiency UCAP (MW) (generation and DR)	161,242.6	162,276.1	159,560.4	156,633.6	139,666.7	G
RPM committed less deficiency ICAP (MW) (generation and DR)	171,662.5	172,781.2	169,348.8	165,260.2	147,141.5	H=G/(1-E)
RPM peak load ICAP (MW)	139,675.0	139,359.3	136,309.0	137,255.2	121,463.5	J=A-B-C
Reserve margin ICAP (MW)	31,987.5	33,421.9	33,039.8	28,005.0	25,678.0	K=H-J
Reserve margin (%)	22.9%	24.0%	24.2%	20.4%	21.1%	L=K/J
Reserve margin in excess of IRM ICAP (MW)	9,499.8	11,124.4	11,911.9	7,828.5	8,065.8	M=K-D*J
Reserve margin in excess of IRM (%)	6.8%	8.0%	8.7%	5.7%	6.6%	N=M/J
RPM peak load UCAP (MW)	131,196.7	130,886.3	128,430.3	130,090.5	115,293.2	P=J*(1-E)
RPM reliability requirement UCAP (MW)	152,315.6	151,832.0	148,331.5	149,210.1	132,006.5	Q=J*F
Reserve margin UCAP (MW)	30,045.9	31,389.8	31,130.1	26,543.1	24,373.5	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	8,927.0	10,444.1	11,228.9	7,423.5	7,660.2	S=G-Q
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	T
Projected reserve margin	22.9%	24.0%	24.2%	20.4%	21.1%	U=(H-T/(1-E))/J-1

Sources of Funding[60]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2021/2022 Delivery Year totaled 35,391.9 MW (82.4 percent of all additions), with 26,320.6 MW from market funding and 9,071.3 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2021/2022 Delivery Year totaled 7,577.6 MW (17.6 percent of all additions), with 5,188.6 MW from market funding and 2,389.0 MW from nonmarket funding. In summary, of the 42,969.5 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2021/2022 Delivery Years, 31,509.2 MW (73.3 percent) were based on market funding.

Of the 6,587.3 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Year, 3,644.4 MW are not yet in service. Of those 3,644.4 MW that have not yet gone into service, 2,244.6 MW have market funding and 1,399.8 MW have nonmarket funding. Applying the historical completion rates, 67.1 percent of all the projects in development are expected to go into service (1,483.2 MW of the 2,244.6 MW of in development market funded projects; 963.3 MW of the 1,399.8 MW of in development nonmarket funded projects). Together, 2,446.6 MW of the 3,644.4 MW of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2023/2024 Delivery Year.

Of the 2,942.9 MW of the additional generation capacity that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years and are already in service, 2,679.8 MW (91.1 percent) are based on market funding and 263.1 MW (8.9 percent) are based on nonmarket funding. In summary, 4,924.2 MW (74.8 percent) of the additional generation capacity (2,244.6 MW not yet in service and 2,679.8 MW in service) that cleared in RPM auctions for the 2022/2023 through 2023/2024 Delivery Years are based on market funding. Capacity additions based on

58 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.

59 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

60 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

nonmarket funding are 1,662.9 MW (25.2 percent) of proposed generation that cleared at least one RPM auction for the 2022/2023 through 2023/2024 Delivery Years.

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

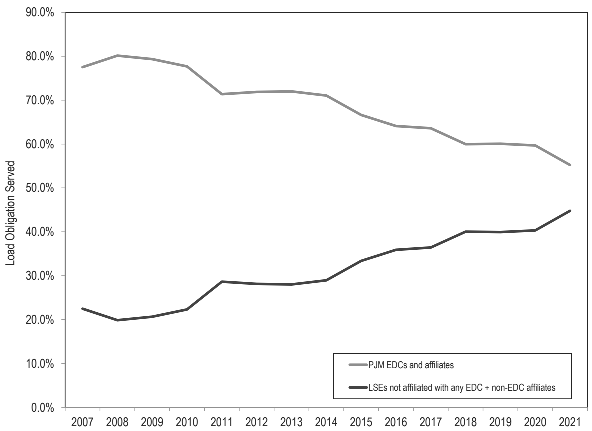
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2021, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 55.2 percent (Table 5-8), down from 59.7 percent on June 1, 2020. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 44.8 percent, up from 40.3 percent on June 1, 2020. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2021, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 55.2 percent on June 1, 2021. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 44.8 percent on June 1, 2021. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2020 and June 1, 2021

	1-Jun-20		1-Jun-21		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	104,849.4	59.7%	96,306.4	55.2%	(8,543.1)	(4.5%)
LSEs not affiliated with any EDC + non EDC Affiliates	70,838.3	40.3%	78,114.1	44.8%	7,275.8	4.5%
Total	175,687.7	100.0%	174,420.4	100.0%	(1,267.3)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2021



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted six months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.[61] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA cleared 27,932.1 MW including 5,574.0 MW of Imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after

61 See "PJM Manual 18: PJM Capacity Market," §7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 51 (October 20, 2021).

the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2022/2023 RPM Base Residual Auction, EMAAC had 4,946.8 MW of CTRs with a total value of $3,737,529, COMED had 2,367.2 MW of CTRs with a total value of $16,381,936, BGE had 4,745.1 MW of CTRs with a total value of $53,188,332 and DEOK had 3,034.8 MW of CTRs with a total value of $24,026,133.

MAAC had 270.1 MW of customer funded ICTRs with a total value of $4,513,768, EMAAC had 40.0 MW of customer funded ICTRs with a total value of $30,222, BGE had 65.7 MW of customer funded ICTRs with a total value of $736,441, COMED had 1,376.0 MW of customer funded ICTRs with a total value of $9,522,470 and DEOK had 155.0 MW of customer funded ICTRs with a total value of $1,227,112.

MAAC had 128.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $2,139,474, EMAAC had 948.0 MW with a value of $716,261 and BGE had 306.0 MW with a value of $3,430,000.

Demand Curve

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[62] Figure 5-4 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2022/2023 RPM Base Residual Auction.

In proposing the downward sloping portion of the VRR curve, PJM asserted that the sloping VRR curve recognizes the value of incremental capacity above the target reserve margin providing additional reliability benefit at a declining rate.[63]

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.[64] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of

62 The formula for the MW level where the VRR curve begins the downward slope is given by (Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)].

63 See 117 FERC ¶ 61,331 (2006).

64 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

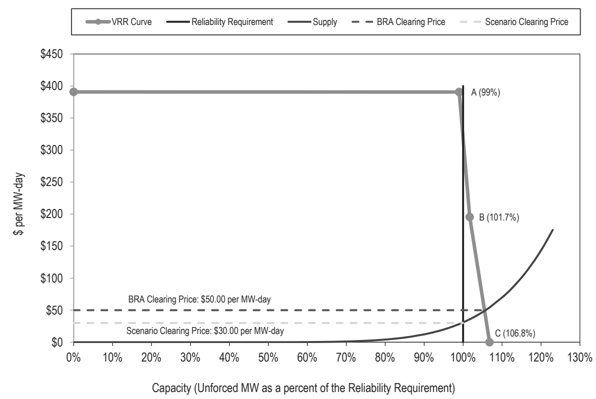
the reliability requirement. The first downward sloping segment is from 99 percent and 101.7 percent of the reliability requirement. The second downward sloping segment is from 101.7 percent and 106.8 percent of the reliability requirement (Figure 5-4).

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the 2022/2023 BRA. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve set equal to the reliability requirement.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $3,916,990,303. If PJM had used a vertical demand curve set equal to the reliability requirement for 2022/2023 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2022/2023 RPM Base Residual Auction would have been $2,659,527,128, a decrease of $1,257,463,175, or 32.1 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 47.3 percent increase in RPM revenues for the 2022/2023 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2022/2023 RPM BRA. The clearing price and cleared quantity would have been lower if a vertical VRR curve set at the reliability requirement had been used in place of the existing VRR curve. In the 2022/2023 BRA, the RTO clearing price would have decreased from $50.00 per MW-day to $30.00 per MW-day, and the clearing quantity would have decreased from 144,477.3 MW to 132,006.7 MW.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2022/2023 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2021/2022 RPM Third Incremental Auction and the 2022/2023 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[65] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[66] [67] [68]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

65 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
66 See OATT Attachment DD § 6.5.
67 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
68 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-9 RSI results: 2019/2020 through 2022/2023 RPM Auctions[69]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1
2019/2020 First Incremental Auction				
RTO	0.63	0.50	53	53
EMAAC	0.00	0.00	5	5
2019/2020 Second Incremental Auction				
RTO	0.61	0.48	38	38
BGE	0.00	0.00	1	1
2019/2020 Third Incremental Auction				
RTO	0.70	0.59	72	72
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2020/2021 Second Incremental Auction				
RTO	0.40	0.56	34	34
2020/2021 Third Incremental Auction				
RTO	0.54	0.72	59	59
MAAC	0.25	0.18	14	14
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0
2021/2022 Third Incremental Auction				
RTO	0.57	0.41	59	59
EMAAC	1.00	0.19	6	6
PSEG	0.00	0.00	1	1
BGE	0.00	-0.00	2	2
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1

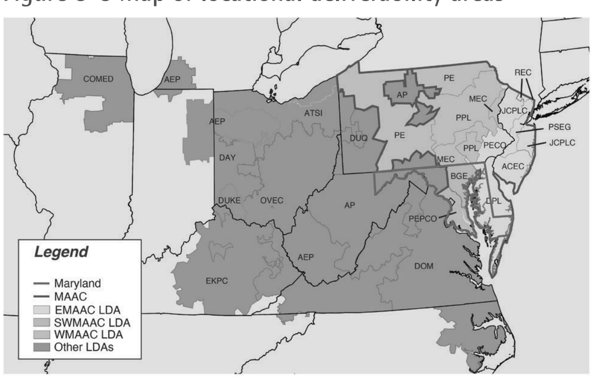
69 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[70] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[71] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[72]

Locational Deliverability Areas are shown in Figure 5-5, Figure 5-6 and Figure 5-7.

Figure 5-5 Map of locational deliverability areas



70 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
71 OATT Attachment DD § 5.10 (a) (ii).
72 146 FERC ¶ 61,052 (2014).

Figure 5-6 Map of RPM EMAAC subzonal LDAs

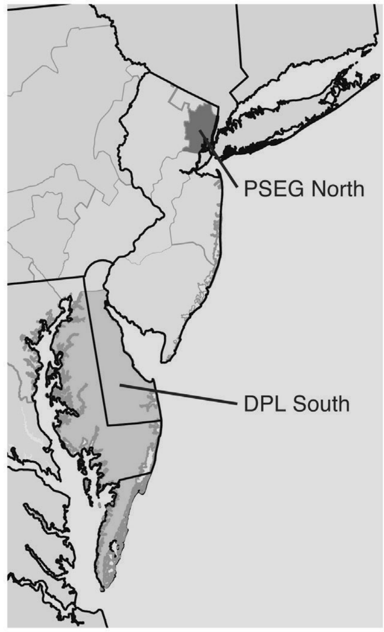
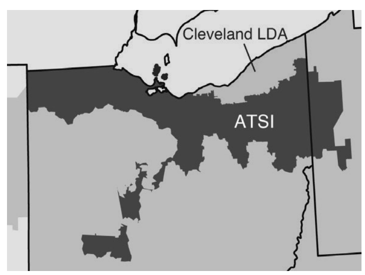


Figure 5-7 Map of RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[73]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the

73 OATT Attachment DD § 5.6.6(b).

obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[74]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[75] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[76] [77] [78] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[79]

74 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).

75 161 FERC ¶ 61,197 (2017).

76 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.

77 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 51 (Oct. 20, 2021).

78 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 51 (Oct. 20, 2021).

79 OATT Schedule 1 § 1.10.1A.

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[80 81] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[82] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[83]

As shown in Table 5-10, of the 1,558.0 MW of imports offered in the 2022/2023 RPM Base Residual Auction, 1,558.0 MW cleared. Of the cleared imports, 954.9 MW (61.3 percent) were from MISO.

Table 5-10 RPM imports: 2007/2008 through 2022/2023 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0

80 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
81 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 51 (Oct. 20, 2021).
82 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
83 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[84] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

There are two categories of demand side products included in the RPM market design for the 2022/2023 BRA:[85 86]

- **Demand Resources (DR).** Interruptible load resource that is offered in an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Energy Efficiency (EE) Resources.** Load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the EE is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention.[87] The peak period definition for the EE Resource type is

84 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017" <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
85 Effective June 1, 2007, the PJM Active Load Management (ALM) program was replaced by the PJM Load Management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered in RPM Auctions as capacity resources and receive the clearing price.
86 Interruptible load for reliability (ILR) is an interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the Second Incremental Auction. The ILR product was eliminated as of the 2012/2013 Delivery Year.
87 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 6, Section L.

even more limited than Limited DR, including only the period from the hour ending 15:00 and the hour ending 18:00 from June through August, excluding weekends and federal holidays. The EE Resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in Incremental Auctions in the 2011/2012 Delivery Year.[88]

Effective with the 2020/2021 Delivery Year, the Capacity Performance product will include two possible season types, annual and summer.

- **Annual Capacity Performance Resources**
  - **Annual Demand Resources.** A Demand Resource that is required to be available on any day during the Delivery Year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.
  - **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Annual Efficiency Resource type includes the period between the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT from January 1 through February 28, excluding weekends and federal holidays.
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A Demand Resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer Period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Summer-Period Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 12,115.9 MW for June 1, 2021, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2021/2022 Delivery Year (16,233.9 MW) less replacement capacity (4,118.0 MW).

88 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Table 5-11 RPM load management statistics by LDA: June 1, 2018 to June 1, 2022[89 90 91]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-18	DR cleared	11,435.4	4,361.9	1,707.2	1,226.4	86.8	389.9	139.2	559.3	1,034.3	287.2	1,895.2	667.1	716.2		
	EE cleared	2,296.3	706.8	315.9	317.6	9.2	102.0	45.2	186.1	184.4	33.2	807.4	131.5	43.1		
	DR net replacements	(3,182.4)	(1,268.4)	(584.3)	(199.5)	(52.4)	(150.9)	(43.6)	(25.6)	(261.0)	(136.7)	(430.0)	(173.9)	(220.0)		
	EE net replacements	248.8	163.0	45.5	107.6	1.1	22.4	9.1	(8.9)	14.7	4.7	29.0	116.5	5.4		
	RPM load management	10,798.1	3,963.3	1,484.3	1,452.1	44.7	363.4	149.9	710.9	972.4	188.4	2,301.6	741.2	544.7		
01-Jun-19	DR cleared	10,703.1	3,878.9	1,659.2	817.0	91.3	381.2	176.5	554.6	1,047.0	333.9	1,759.9	262.4	741.4		
	EE cleared	2,528.5	821.4	395.3	301.7	7.8	134.5	52.8	170.0	204.8	41.7	792.9	131.7	72.7		
	DR net replacements	(2,138.8)	(1,004.2)	(468.8)	(129.0)	(40.9)	(141.5)	(86.6)	(74.8)	(130.3)	(123.1)	(143.0)	(54.2)	(208.9)		
	EE net replacements	(50.0)	(24.1)	4.7	3.3	(0.2)	2.7	9.1	2.2	3.4	0.0	0.0	1.1	(20.4)		
	RPM load management	11,042.8	3,672.0	1,590.4	993.0	58.0	376.9	151.8	652.0	1,124.9	252.5	2,409.8	341.0	584.8		
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,427.7	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,806.2	1,810.5	979.1	501.1	42.0	353.1	136.0	275.9	420.5	95.7	982.7	225.2	186.7	111.0	135.5
	DR net replacements	(4,111.0)	(1,302.8)	(568.4)	(160.8)	(28.1)	(195.8)	(100.2)	(106.5)	(483.2)	(137.4)	(609.5)	(54.3)	(235.1)	(50.9)	(90.2)
	EE net replacements	(7.0)	0.0	0.0	(1.1)	0.1	0.0	34.9	(2.6)	80.0	7.0	10.6	1.5	(1.7)	8.0	(17.5)
	RPM load management	12,115.9	3,961.8	1,792.2	964.1	80.3	567.8	259.3	512.7	1,214.1	238.1	2,457.5	451.4	647.6	295.8	248.3
01-Jun-22	DR cleared	8,811.9	2,817.4	1,139.9	485.3	48.4	294.6	93.8	322.7	924.1	166.5	1,511.0	162.6	661.7	210.5	185.1
	EE cleared	4,810.6	1,974.4	1,090.8	463.7	49.6	384.4	182.6	263.8	417.0	41.8	723.9	199.9	242.1	91.8	145.9
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	13,622.5	4,791.8	2,230.7	949.0	98.0	679.0	276.4	586.5	1,341.1	208.3	2,234.9	362.5	903.8	302.3	331.0

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2022[92 93 94]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,811.9	0.0	0.0	8,811.9	0.0	8,811.9	0.0	1.087	0.0

89 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

90 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.

91 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

92 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

93 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

94 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2022[95 96]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,806.2	0.0	(7.0)	4,799.2	0.0	4,799.2
01-Jun-22	4,810.6	0.0	0.0	4,810.6	0.0	4,810.6

Capacity Value of Intermittent Resources (ELCC)

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value of renewables is calculated correctly.

The contribution of intermittent and storage resources to reliability has been addressed in the PJM capacity market using derating factors in order to help ensure that MW of capacity are comparable, regardless of the source. Derating factors were used in the 2022/2023 BRA. On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators based on the effective load carrying capability (ELCC) method.[97] The MMU opposed the new ELCC rules because they fail to incorporate the marginal ELCC value of resources, rely on significant counterfactual behavioral assumptions, do not apply to all resource types, and use invented (putative) data as key inputs, among other issues, but does not oppose the ELCC approach in concept and when done correctly.[98] PJM's flawed ELCC approach will create new issues for the PJM Capacity Markets unless addressed promptly. If done correctly, including the application of ELCC to all resources, ELCC could be an advance over the current approach to defining the MW of capacity provided by all resource types, including intermittent resources.

PJM's flawed ELCC approach, based on static average rather than dynamic, market defined marginal values and basing the results on incorrect assumptions about the dispatch of some resource types, will create new issues for the PJM Capacity Markets unless addressed in the near future. If done correctly, ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources, but only if done correctly and only if all the required assumptions are made explicit and decided explicitly.

Derating factors and ELCC values are used in capacity auctions to convert the nameplate capacity of intermittent and storage resources into MW of capacity equivalent to resources that can produce for any of the 8,760 hours in a year. Both the capacity derating factors applied to intermittent nameplate capacity in the 2022/2023 BRA and the ELCC calculations to be used for future capacity auctions are based on the assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the

95 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

96 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE addback rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

97 See 176 FERC ¶ 61,056. There are multiple ways to apply the ELCC method. There is not a single ELCC method.

98 Comments and Motions of the Independent Market Monitor for PJM, Docket No. ER21-278 and EL19-100 (November 20, 2020). Answer and Motion for Leave to Answer and Alternative Motion for Consolidation of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 10, 2020). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 18, 2020). Comments and Motions of the Independent Market Monitor for PJM, ER21-278-001 (March 22, 2021). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (April 28, 2021).

defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity.

The definition of intermittent capacity is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity.

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[99] [100] [101] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps are defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[102] For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[103] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[104] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/nonperformance charges.[105] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for auctions for delivery years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific

99 See OATT Attachment DD § 6.5.

100 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

101 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

102 176 FERC ¶ 61,137 (September 2, 2021).

103 OATT Attachment DD § 6.8 (b).

104 *PJM Interconnection L.L.C., Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery* (February 14, 2019).

105 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2021/2022 RPM Base Residual Auction—Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

components of avoidable costs are defined in the PJM tariff.[106]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[107] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Competitive Offers

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (net ACR) including gross ACR, forward looking net revenues and the impact of the resource's performance during performance assessment intervals (A) in the delivery year on its risk and the cost to mitigate that risk.[108]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[109]

Under the original Capacity Performance design, the competitive offer of a resource was the larger of the opportunity cost of taking on a CP obligation (the default offer cap), or a unit specific offer cap based on its net ACR. But the default offer cap defined in the PJM tariff was based on strong assumptions that are not correct. The default offer cap was based on the opportunity cost of taking on a CP obligation when the resource could have earned enough revenues by staying as an energy only resource and earned enough bonus revenues to cover its avoidable costs. If the resource's net avoidable costs are higher than the bonuses it expects to earn during performance assessment intervals in the delivery year, its competitive offer is its net ACR adjusted with any bonuses or nonperformance charges it may incur during the delivery year.

The basic assumptions of the Capacity Performance design are not correct and as a result the competitive offer is not Net CONE times B. Two of the core assumptions are that it is reasonable to expect 360 PAI and that it is reasonable to expect that the bonus performance payment rate (bonus rate or CPBR) is equal to the nonperformance charge rate (penalty rate or PPR). There have been effectively zero true PAI since the introduction of the capacity performance model. This does not mean that there will never be PAI or that there will never be 360 PAI. It does mean that it is not reasonable to include the assumption of 360 PAI in establishing the definition of a competitive offer in the capacity market. It does mean that there is no accurate way to calculate expected PAI for the market and that a design based on that calculation will not be based on market fundamentals. The bonus rate has been

106 OATT Attachment DD § 6.8(a).
107 151 FERC ¶ 61,208.
108 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.
109 OATT Attachment DD § 10A (d).

significantly lower than the penalty rate and there is no reason to expect that to change. As a result, it is not reasonable to include the assumption that CPBR equals PPR in defining a competitive offer in the capacity market. PJM's interpretation of the rules has led to the ability of nonperforming or underperforming resources to avoid penalty payments and to a corresponding reduction in bonus payments. It is not consistent with actual capacity market rules to include the assumption that a generation unit is forgoing energy only status when it decides on a capacity market offer. The PJM Capacity Market has a must offer requirement for a reason; it is required in order to prevent the exercise of market power, particularly given the must buy obligation of load. If a capacity market seller wants to convert to energy only status, the owner must give up its CIRs. Such CIRs could be expensive and difficult to reacquire if the capacity market seller decided to reenter the capacity market.

The Net CONE times B offer caps are equivalent to assuming the worst case outcome as defined by the number of PAI and unit performance and permitting generation owners to use that worst case to define offers. It is more accurate and consistent with market logic to reflect the cost of mitigating the risk of making offers, in the presence of the risk of capacity market penalties, through the CPQR component of the ACR. The CPQR component is the cost of mitigating the risk faced by the generator rather than the full cost of the worst case scenario. Use of the CPQR component also permits generation owners to include their own views of the key market parameters in the calculation of the cost to mitigate risk, within a reasonable range, and subject to market power review.

Net CONE times B was clearly well in excess of a competitive offer in the 2022/2023 BRA whether compared to net ACR offers or compared to the actual offers of market participants. While the offer cap provided almost unlimited optionality to generation owners in setting offers, the actual clearing prices based on actual offers were generally about half of the offer caps. But some generation owners did successfully exercise market power within this design.

The clearing prices for CP Resources were less than Net CONE times B for every zone. Of the 22 identified zones, the clearing price was less than 50 percent of Net CONE times B in 14 zones and less than 60 percent in 20 zones. The clearing price in BGE Zone was 68.4 of Net CONE times B and the clearing price in Penelec Zone, where Net CONE was lower than other zones, was 78.4 of Net CONE times B. Overall, the average clearing price was 43.6 percent of the average Net CONE times B.[110]

2021/2022 RPM Third Incremental Auction

As shown in Table 5-14, 481 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Third Incremental Auction. Unit specific offer caps were calculated for zero generation resources (0.0 percent). Of the 481 generation resources, 415 generation resources had the Net CONE times B offer cap (86.3 percent), 28 generation resources elected the offer cap option of 1.1 times the BRA clearing price (5.8 percent), 11 Planned Generation Capacity Resources had uncapped offers (2.3 percent), and the remaining 27 generation resources were price takers (5.6 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2022/2023 RPM Base Residual Auction

As shown in Table 5-14, 1,083 generation resources submitted Capacity Performance offers in the 2022/2023 RPM Base Residual Auction. Unit specific offer caps were not calculated for any generation resources (0.0 percent). Of the 1,083 generation resources, 872 generation resources had the Net CONE times B offer cap (80.5 percent), 35 Planned Generation Capacity Resources had uncapped offers (3.2 percent), 40 generation resources had uncapped planned uprates plus Net CONE times B offer cap for the existing portion of the units (3.7 percent), four generation resources had uncapped planned uprates and were price takers for the existing portion of the unit (0.4 percent), and the remaining 132 generation resources were price takers (12.2 percent). Market power mitigation was not applied to any Capacity Performance sell offers.

110 See "Analysis of the 2022/2023 RPM Base Residual Auction," at 27, Table 3 (February 22, 2022) <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>

Table 5-14 ACR statistics: RPM auctions conducted in 2021

	2021/2022 Third Incremental Auction		2022/2023 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA	NA	NA
Unit specific ACR (APIR)	0	0.0%	0	0.0%
Unit specific ACR (APIR and CPQR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%
Default ACR and opportunity cost	NA	NA	NA	NA
Net CONE times B	415	86.3%	872	80.5%
Offer cap of 1.1 times BRA clearing price elected	28	5.8%	NA	NA
Uncapped planned uprate and default ACR	NA	NA	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	0	0.0%	40	3.7%
Uncapped planned uprate and price taker	0	0.0%	4	0.4%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%	NA	NA
Uncapped planned generation resources	11	2.3%	35	3.2%
Existing generation resources as price takers	27	5.6%	132	12.2%
Total Generation Capacity Resources offered	481	100.0%	1,083	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[111] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative approaches.[112] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[113]

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[114] The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[115]

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[116] The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2022/2023 BRA.

111 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).
112 Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).
113 *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).
114 *PJM Interconnection, L.L.C*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).
115 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).
116 173 FERC ¶ 61,134 (2020).

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[117] The MMU has recommended such an approach. The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2022/2023 BRA. This decision was reversed in the Commission's order related to the ORDC matter.[118]

Issues addressed during the MOPR unit specific review process in 2021 for the 2022/2023 BRA included documentation of asset life greater than 20 years, degradation of resource performance, operating and maintenance expenses, required capital expenditures, tax assumptions, documentation of forward net revenues, and the use of retail savings as a source of net revenue offset to EE gross CONE. The MMU did not agree with PJM's judgments about parameters and calculations of MOPR floors in a significant number of cases (Table 5-15).

MOPR Statistics

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-15, of the 838.5 ICAP MW of MOPR Unit-Specific Exception requests for the 2021/2022 RPM Third Incremental Auction, requests for 838.5 MW were granted.

As shown in Table 5-15, of the 13,149.2 ICAP MW of MOPR Unit-Specific Exception and Resource-Specific Exception requests for the 2022/2023 RPM Base Residual Auction, the MMU agreed with requests for 6,794.7 MW.

Table 5-15 MOPR statistics: RPM auctions conducted in 2021[119]

				ICAP (MW)			UCAP (MW)	
	MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
2021/2022 Third Incremental Auction	Capacity Resources with No State Subsidy	Unit Specific Exception	77	838.5	838.5	248.2	246.5	103.9
	Capacity Resources with No State Subsidy	Default	NA	NA	NA	82.1	81.4	0.0
	Total		77	838.5	838.5	330.3	327.9	103.9
2022/2023 Base Residual Auction	Capacity Resources with No State Subsidy	Unit Specific Exception	148	8,849.0	4,882.7	1,720.0	1,702.4	490.3
	Capacity Resources with State Subsidy - Cleared	Resource Specific Exception	2	2,134.0	1,240.0	2,134.0	2,126.1	2,126.1
	Capacity Resources with State Subsidy - New	Resource Specific Exception	109	2,166.2	672.0	1,207.1	1,248.5	1,104.4
	Capacity Resources with No State Subsidy	Default	NA	NA	NA	116.7	98.9	0.0
	Capacity Resources with State Subsidy - Cleared	Default	NA	NA	NA	6,590.9	6,332.9	4,954.7
	Capacity Resources with State Subsidy - New	Default	NA	NA	NA	459.8	493.0	153.1
	Total		259	13,149.2	6,794.7	12,228.5	12,001.7	8,828.6

Replacement Capacity[120]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

117 173 FERC ¶ 61,134 (2020).
118 177 FERC ¶ 61,209 (2021).
119 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers are not reported as a result of PJM confidentiality rules.
120 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2022. The 2022 numbers are not final.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.[121]

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2022

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	144,477.3	0.0	0.0	144,477.3	0.0	144,477.3

121 See Monitoring Analytics, LLC, "Analysis of the 2021/2022 RPM Base Residual Auction – Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for all RPM auctions held through 2021, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through 2021.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA from the 2018/2019 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through 2021. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through 2021 based on the unforced MW cleared and the resource clearing prices. In the 2019/2020 Delivery Year RPM revenue was $7.1 billion. In the 2020/2021 Delivery Year, RPM revenue was $7.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through 2021. In 2019, RPM revenue was $8.7 billion. In 2020, RPM revenue was $7.1 billion.

Table 5-22 shows the RPM annual charges to load. For the 2019/2020 Delivery Year, RPM annual charges to load were $7.0 billion. For the 2020/2021 Delivery Year, annual charges to load are $7.0 billion.

Table 5-17 Capacity market clearing prices: 2019/2020 through 2022/2023 RPM Auctions[122]

		RPM Clearing Price ($ per MW-day)													
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30	$80.00
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30	$80.00
2019/2020 BRA	Capacity Performance	$100.00	$100.00	$100.00	$100.00	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$202.77	$100.30	$100.00
2019/2020 First Incremental Auction	Base Capacity	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Capacity Performance	$51.33	$51.33	$51.33	$51.33	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33	$51.33
2019/2020 Second Incremental Auction	Base Capacity	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14	$10.01
2019/2020 Second Incremental Auction	Base Capacity DR/EE	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14	$10.01
2019/2020 Second Incremental Auction	Capacity Performance	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00	$32.87
2019/2020 Third Incremental Auction	Base Capacity	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Base Capacity DR/EE	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$20.00	$21.35	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Capacity Performance	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35
2020/2021 BRA	Capacity Performance	$76.53	$86.04	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$188.12	$86.04	$76.53
2020/2021 First Incremental Auction	Capacity Performance	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90
2020/2021 Second Incremental Auction	Capacity Performance	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25
2020/2021 Third Incremental Auction	Capacity Performance	$10.00	$15.25	$10.00	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$10.00	$10.00	$15.25	$10.00
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55
2022/2023 BRA	Capacity Performance	$50.00	$95.79	$50.00	$95.79	$97.86	$95.79	$97.86	$97.86	$97.86	$95.79	$50.00	$68.96	$126.50	$71.69

122 See the *2019 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market

Table 5-18 Capacity market cleared MW: 2019/2020 through 2022/2023 RPM Auctions[123]

		UCAP (MW)													
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	TOTAL
2019/2020	BASE	57,090.2	9,996.2	9,066.6	12,754.9	20,382.4	1,598.5	5,583.1	3,228.9	6,971.7	10,291.1	22,971.4	4,422.9	2,971.6	167,329.5
2019/2020	FIRST	774.9	249.4	39.3	157.7	78.7	11.7	10.6	28.8	43.6	147.5	711.4	31.9	9.6	2,295.1
2019/2020	SECOND	435.6	160.4	30.1	146.2	210.1	21.2	38.1	44.8	41.9	263.6	105.8	107.5	7.3	1,612.6
2019/2020	THIRD	1,531.9	440.9	429.4	1,216.6	265.7	2.4	180.4	23.2	83.6	454.2	867.4	255.2	76.1	5,827.0
2020/2021	BASE	53,574.6	11,413.2	8,990.6	14,398.2	19,978.5	1,647.2	5,041.2	2,975.4	6,410.0	9,925.9	23,960.3	4,021.1	2,437.8	164,773.9
2020/2021	FIRST	1,245.3	331.0	144.2	83.4	76.2	38.9	105.8	32.0	97.8	666.9	644.4	38.7	20.3	3,524.8
2020/2021	SECOND	415.7	206.9	53.0	30.7	302.9	28.4	29.5	48.8	35.4	366.2	194.6	160.3	31.5	1,903.8
2020/2021	THIRD	961.2	569.7	118.7	89.0	194.1	33.1	423.0	137.0	93.1	554.3	127.7	39.8	145.4	3,486.0
2021/2022	BASE	52,896.5	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	2,746.1	163,627.3
2021/2022	FIRST	194.1	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	2,143.2
2021/2022	SECOND	1,242.5	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	3,707.5
2021/2022	THIRD	1,638.4	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	5,235.0
2022/2023	BASE	37,732.2	12,804.7	10,147.4	14,118.7	23,658.8	1,305.3	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	144,477.3

Table 5-19 Weighted average clearing prices by zone: 2019/2020 through 2022/2023

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2019/2020	2020/2021	2021/2022	2022/2023
RTO				
AEP	$93.63	$74.42	$133.84	$50.00
APS	$93.63	$74.42	$133.84	$50.00
ATSI	$92.97	$69.75	$142.59	$50.00
Cleveland	$89.17	$68.93	$90.81	$50.00
COMED	$188.90	$182.15	$189.54	$69.02
DAY	$93.63	$72.42	$132.69	$50.00
DUKE	$93.63	$121.24	$127.66	$71.66
DUQ	$93.63	$74.42	$133.84	$50.00
DOM	$93.63	$74.42	$133.84	$50.00
EKPC	$93.63	$74.42	$133.84	$50.00
MAAC				
EMAAC				
ACEC	$112.48	$182.04	$158.72	$97.79
DPL	$112.48	$182.04	$158.72	$97.79
DPL South	$115.95	$178.65	$159.65	$97.86
JCPLC	$112.48	$182.04	$158.72	$97.79
PECO	$112.48	$182.04	$158.72	$97.79
PSEG	$110.56	$165.74	$184.82	$97.77
PSEG North	$116.03	$176.45	$190.48	$97.82
REC	$112.48	$182.04	$158.72	$97.79
SWMAAC				
BGE	$88.20	$80.71	$174.43	$126.49
PEPCO	$90.59	$84.24	$133.37	$95.19
WMAAC				
MEC	$93.81	$81.85	$134.56	$95.79
PE	$93.81	$81.85	$134.56	$95.79
PPL	$88.53	$85.07	$138.51	$95.77

123 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2022/2023[124]

Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$74.28	144,477.3	365	$3,916,953,841

Table 5-21 RPM revenue by calendar year: 2007 through 2023[125]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$104.50	156,985.8	365	$6,183,448,991
2023	$74.28	59,770.1	151	$1,620,438,438

124 The results for the ATSI Integration Auctions are not included in this table.
125 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-8 History of capacity prices: 1999/2000 through 2022/2023[126]

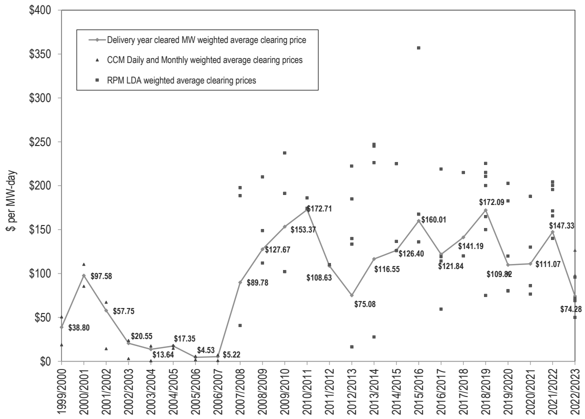
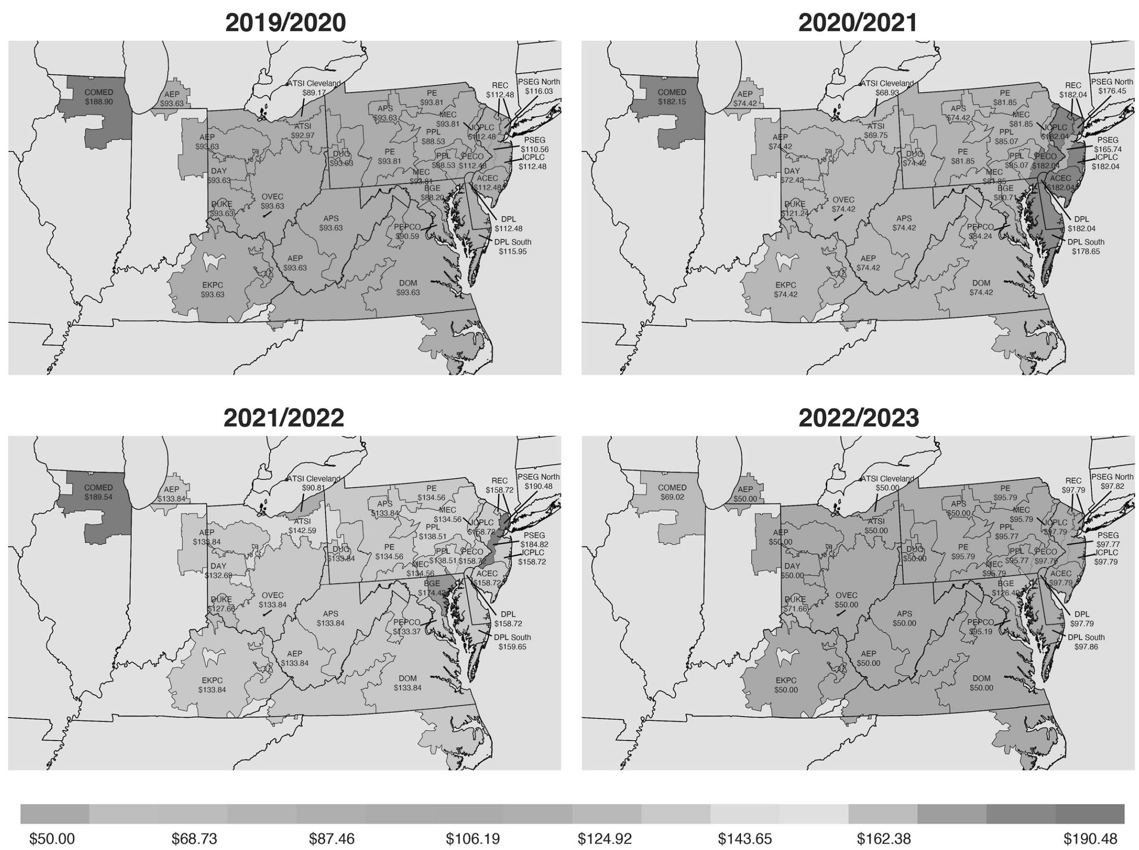


Figure 5-9 Map of RPM capacity prices: 2019/2020 through 2022/2023



126 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2021/2022 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Table 5-22 RPM cost to load: 2019/2020 through 2022/2023 RPM Auctions[127 128 129]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2019/2020			
Rest of RTO	$98.07	89,185.9	$3,201,364,940
Rest of EMAAC	$115.58	24,415.1	$1,032,810,556
BGE	$97.79	7,595.2	$271,828,430
COMED	$192.56	24,985.1	$1,760,892,086
PEPCO	$92.90	7,330.3	$249,230,694
PSEG	$115.83	11,281.1	$478,247,326
Total		164,792.8	$6,994,374,033
2020/2021			
Rest of RTO	$77.31	69,073.7	$1,949,098,489
Rest of MAAC	$87.06	29,555.9	$939,246,366
EMAAC	$174.32	35,740.4	$2,274,098,760
COMED	$189.92	23,744.7	$1,645,988,210
DUKE	$104.50	5,072.0	$193,459,838
Total		163,186.7	$7,001,891,663
2021/2022			
Rest of RTO	$142.16	82,768.3	$4,294,838,410
Rest of EMAAC	$164.73	23,719.9	$1,426,178,211
ATSI	$160.21	13,995.4	$818,411,597
BGE	$163.50	7,491.2	$447,049,048
COMED	$198.43	22,721.2	$1,645,630,168
PSEG	$188.46	10,987.4	$755,803,998
Total		161,683.4	$9,387,911,433
2022/2023			
Rest of RTO	$50.09	51,125.9	$934,814,759
EMAAC	$97.75	35,300.9	$1,259,545,677
WMAAC	$96.42	15,495.6	$545,317,684
BGE	$107.92	7,611.3	$299,826,001
COMED	$67.17	22,940.7	$562,472,028
DUKE	$59.38	5,304.6	$114,962,107
PEPCO	$95.97	6,698.3	$234,639,139
Total		144,477.3	$3,951,577,394

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[130 131 132 133 134 135] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited

127 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.

128 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.

129 The net load prices and obligation MW for 2021/2022 are not finalized.

130 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," , <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

131 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

132 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).

133 In the Matter of the Investigation of Resource Adequacy Alternatives, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

134 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

135 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

CRF Issue[136]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct. These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[137] In the filing PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[138] [139]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1-\frac{sB}{\sqrt{1+r}}-s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{m_j}{(1+r)^j}\right]}{(1-s)\sqrt{1+r}\,[(1+r)^N-1]}$$

136 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).

137 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket ER21-1844-000 (May 4, 2021).

138 See "Comments of the Independent Market Monitor for PJM,"ER21-1844-000 (May 25, 2021).

139 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket ER21-1635-000.

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the CRF formula be included in the tariff.[140] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-24 shows the CRFs that are currently posted. The values in Table 5-24 were calculated using the formula above and the financial assumptions in Table 5-25. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-23 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
m_j	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

The MMU supports the changes to the tariff to correct the application of CRF to the capacity market but there are still unresolved issues. The tariff revisions lack clarity about how CRF values will be determined in the future and to which projects they apply, and lack clarity about how CRF values would be applied to APIR for project costs that are currently being recovered. For example, Table 5-24, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.[141] For example, a project that can use the depreciation provisions relevant for the 2023/2024 Delivery Year uses the depreciation provisions once and those provisions affect the project's CRF for its entire life, regardless of the CRF values in the table for subsequent delivery years. However, changes in the tax rate apply each year and if the tax rate changes

140 Order 176 FERC ¶61,003 (July 2, 2021).

141 See "Capital Recovery Factors ("CRF") for Avoidable Project Investment Cost ("APIR") Determinations," <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/crf-values-for-apir-determination.ashx>.

the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-24 for delivery years after 2022/2023 would not apply to the calculation of APIR values for projects that go into service for the 2022/2023 Delivery Year. A similar issue exist for projects that were assigned a CRF under the previous tariff rules. The change in the tax rate should be reflected in the CRF going forward. PJM does not plan to do this and the Commission indicated that the issue is "beyond the scope" of the PJM filing.[142]

Table 5-24 Levelized CRF values: Delivery Year 2022/2023 through Delivery Year 2025/2026

Age of Existing Units (Years)	Remaining Life of Plant	Levelized CRF 2022/2023	Levelized CRF 2023/2024	Levelized CRF 2024/2025	Levelized CRF 2025/2026
1 to 5	30	0.088	0.091	0.094	0.096
6 to 10	25	0.093	0.096	0.098	0.101
11 to 15	20	0.101	0.104	0.107	0.110
16 to 20	15	0.116	0.119	0.122	0.126
21 to 25	10	0.147	0.152	0.158	0.164
25 Plus	5	0.246	0.258	0.271	0.283
Mandatory CapEx	4	0.296	0.312	0.328	0.345
40 Plus Alternative	1	1.100	1.100	1.100	1.100

Table 5-25 Financial parameter and tax rate assumptions for CRF calculations

Financial Parameter	Parameter Value
Equity Funding Percent	45.000%
Debt Funding Percent	55.000%
Equity Rate	13.000%
Debt Interest Rate	6.000%
Federal Tax Rate	21.000%
State Tax Rate	9.300%
Effective Tax Rate	28.347%
After tax Weighted Average Cost of Capital	8.215%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU at least 90 days prior to the proposed deactivation date. Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[143] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[144]

Table 5-26 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through December 2021. Of the 119 deactivation requests submitted, 20 units (16.8 percent) deactivated an average of 214 days earlier than their initially requested date; 12 units (10.1 percent) deactivated an average of 95 days later than the originally requested deactivation date; and 28 units (23.5 percent) deactivated on their initially requested date. Fifteen (12.6 percent) of the unit deactivations were cancelled an average of 351 days before their scheduled deactivation date, and 44 (37.0 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-27 shows this information broken out by fuel types.

Table 5-26 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through December 2021

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	20	16.8%	(214)
Late	12	10.1%	95
On time	28	23.5%	0
Cancelled	15	12.6%	(351)
Pending	44	37.0%	-
Total	119	100.0%	-

142 Order 176 FERC ¶61,003 (July 2, 2021) at 28.
143 OATT Attachment DD § 6.6(g).
144 OATT Part V §113

Table 5-27 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through December 2021

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	100.0%	(4)
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		2	100.0%	-
Coal	Early	9	25.7%	(268)
	Late	5	14.3%	108
	On time	7	20.0%	0
	Cancelled	2	5.7%	(832)
	Pending	12	34.3%	-
Total		35	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	4	100.0%	-
Total		4	100.0%	-
Methane	Early	4	20.0%	(107)
	Late	5	25.0%	75
	On time	7	35.0%	0
	Cancelled	2	10.0%	(190)
	Pending	2	10.0%	-
Total		20	100.0%	-
Natural Gas	Early	3	20.0%	(262)
	Late	1	6.7%	12
	On time	7	46.7%	0
	Cancelled	0	0.0%	-
	Pending	4	26.7%	-
Total		15	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
Total		10	100.0%	-
Oil	Early	2	7.4%	(326)
	Late	1	3.7%	213
	On time	3	11.1%	0
	Cancelled	1	3.7%	(105)
	Pending	20	74.1%	-
Total		27	100.0%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		1	100.0%	-
Storage	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	3	60.0%	0
	Cancelled	0	0.0%	-
	Pending	2	40.0%	-
Total		5	100.0%	-

Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.[145] The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[146]

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[147] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[148] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.[149] The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.[150] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[151] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[152]

145 OATT Part V §114
146 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").
147 OATT § 113.2; OATT Attachment M § IV.1.
148 OATT § 113.2.
149 *Id.*
150 OATT § 113.1.
151 OATT Attachment DD § 6.6(g).
152 *Id.*

Under the current rules, a unit providing RMR service can recover its costs under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[153] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit." [154] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[155] The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.[156] Project investment is capped at $2 million, above which FERC approval is required.[157] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[158]

Table 5-28 shows units that have provided RMR service to PJM. PJM has indicated to another plant that RMR service will be required in 2022.

In each of the cost of service recovery rate filings for RMR service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate and costs associated with closing the unit that would have been incurred regardless of the RMR service period.[159] In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.[160] Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary

Table 5-28 RMR service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

153 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
154 OATT § 115.
155 *Id.*
156 OATT § 118.
157 OATT §§ 115, 117.
158 OATT § 119.
159 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
160 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.

in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual incremental costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that RMR service should be provided under the deactivation avoidable cost rate in Part V, and that the revenue cap under the avoidable cost rate option be eliminated.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual incremental costs associated with the RMR service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-29 shows the capacity factors by unit type for 2020 and 2021. In 2021, nuclear units had a capacity factor of 95.0 percent, compared to 96.1 percent in 2020; combined cycle units had a capacity factor of 61.8 percent in 2021, compared to a capacity factor of 60.1 percent in 2020; coal units had a capacity factor of 42.0 percent in 2021, compared to 34.4 percent in 2020.

Table 5-29 Capacity factor (By unit type (GWh)): 2020 and 2021[161 162 163]

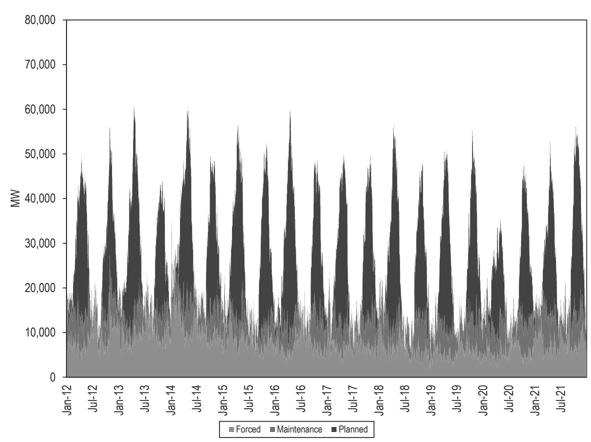
	2020		2021		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2021 from 2020
Battery	36.1	1.2%	36.5	1.3%	0.0%
Combined Cycle	289,902.1	60.1%	285,458.6	61.8%	1.6%
Single Fuel	252,301.6	65.6%	251,731.8	69.0%	3.4%
Dual Fuel	37,600.4	38.6%	33,726.8	34.7%	(4.0%)
Combustion Turbine	19,213.8	7.5%	20,320.5	8.0%	0.5%
Single Fuel	13,245.3	7.4%	14,906.4	8.4%	1.0%
Dual Fuel	5,968.5	7.8%	5,414.1	7.1%	(0.7%)
Diesel	282.5	8.3%	311.7	9.1%	0.8%
Single Fuel	273.4	9.0%	292.6	9.5%	0.6%
Dual Fuel	9.1	2.5%	19.1	5.3%	2.8%
Diesel (Landfill gas)	1,560.5	56.2%	1,450.6	55.5%	(0.7%)
Fuel Cell	226.6	90.9%	220.8	88.9%	(2.1%)
Nuclear	276,607.6	96.1%	272,670.4	95.0%	(1.1%)
Pumped Storage Hydro	6,049.3	12.4%	6,091.8	12.5%	0.1%
Run of River Hydro	10,374.0	39.7%	10,533.0	40.4%	0.7%
Solar	3,812.0	16.8%	7,335.0	19.3%	2.5%
Steam	165,306.2	30.2%	189,970.0	36.6%	6.4%
Biomass	5,533.8	65.3%	5,770.9	70.3%	5.0%
Coal	152,358.3	34.3%	178,280.9	42.0%	7.7%
Single Fuel	149,895.3	36.0%	173,535.0	43.0%	7.1%
Dual Fuel	2,463.0	8.9%	4,745.9	22.3%	13.4%
Natural Gas	6,262.9	40.6%	4,878.3	41.1%	0.5%
Single Fuel	426.7	49.5%	523.0	51.7%	2.2%
Dual Fuel	5,836.2	20.5%	4,355.3	18.1%	(2.4%)
Oil	1,151.3	2.6%	1,039.9	3.4%	0.9%
Wind	26,430.7	29.3%	27,650.7	28.4%	(0.9%)
Total	799,801.5	45.2%	822,049.5	47.2%	2.0%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[164] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[165] If a proposed maintenance outage scheduled within the PJM Peak Period Maintenance Season is not approved by PJM and the generation owner takes the outage, the outage must be classified as a forced outage, or the generation owner may buy replacement capacity, or pay a Peak Season Maintenance Compliance Penalty Charge.[166 167] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-10, as a result of restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-14.

Figure 5-10 Outages (MW): 2012 through 2021

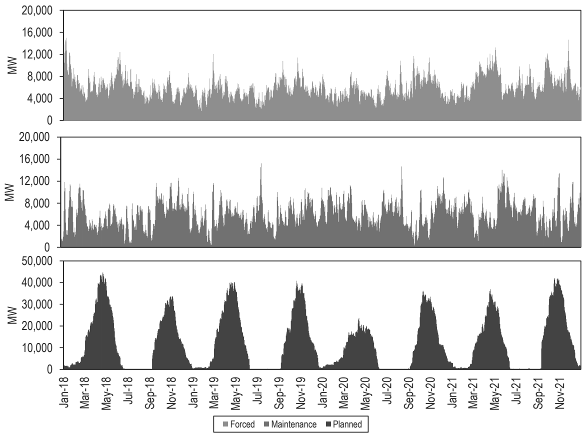


In 2020, planned, maintenance and forced outages were lower than in 2019 (Figure 5-11). The MWh of planned outages were 26 percent lower than in 2019. The MWh of maintenance outages were 7 percent lower than in 2019. The MWh of forced outages were 20 percent lower

161 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
162 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
163 The capacity factor values are modified from previously reported values because of a calculation error which has been fixed.
164 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 40 (Dec. 15, 2021).
165 OATT, Attachment K (Appendix) § 1.9.3 (b).
166 OATT, Attachment DD (Reliability Pricing Model) § 9 (b).
167 PJM "eDART User Guide," Maintenance Outages, Rev. 11 (Feb. 11, 2022), p. 31.

than in 2019. Planned outages were 31 percent higher, maintenance outages were 2 percent higher, and forced outages were 24 percent higher in 2021 than in 2020.

Figure 5-11 Forced, maintenance and planned outages (MW): 2018 through 2021



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-12. Metrics by unit type are shown in Table 5-30.

Figure 5-12 Equivalent outage and availability factors: 2007 to 2021

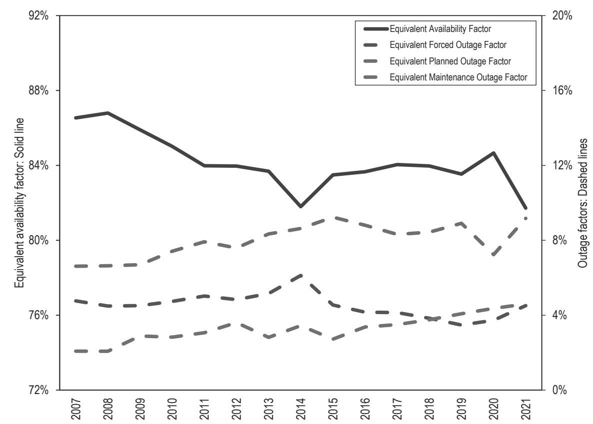


Table 5-30 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2021

	Coal				Combined Cycle				Combustion Turbine				Diesel			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.3%	8.6%	2.7%	81.4%	2.5%	6.1%	1.7%	89.7%	4.4%	2.7%	2.5%	90.4%	10.2%	0.6%	1.6%	87.6%
2008	7.3%	7.1%	2.4%	83.1%	2.1%	6.2%	1.7%	90.0%	2.8%	4.5%	2.2%	90.5%	9.1%	1.0%	1.2%	88.7%
2009	6.6%	8.5%	3.6%	81.3%	2.8%	6.5%	3.3%	87.4%	1.7%	2.8%	2.5%	93.0%	6.6%	0.6%	1.1%	91.7%
2010	7.8%	8.9%	4.1%	79.2%	2.6%	8.4%	3.1%	85.9%	2.1%	2.8%	2.0%	93.1%	4.4%	0.4%	1.5%	93.6%
2011	8.2%	9.2%	4.4%	78.2%	2.5%	9.5%	2.3%	85.7%	2.2%	3.7%	2.4%	91.7%	3.3%	0.1%	1.9%	94.8%
2012	7.6%	9.0%	6.0%	77.4%	3.7%	7.9%	2.2%	86.1%	2.8%	3.4%	1.6%	92.2%	3.9%	0.7%	2.4%	93.0%
2013	8.4%	10.6%	4.5%	76.5%	1.9%	9.1%	2.4%	86.6%	5.3%	4.4%	1.5%	88.8%	6.0%	0.3%	1.4%	92.4%
2014	9.7%	9.8%	5.4%	75.1%	2.7%	10.0%	2.5%	84.7%	6.6%	4.2%	1.8%	87.4%	14.0%	0.4%	2.0%	83.6%
2015	7.7%	10.7%	3.9%	77.7%	2.3%	10.3%	2.0%	85.4%	2.8%	4.7%	1.9%	90.6%	7.7%	0.3%	2.7%	89.3%
2016	7.5%	9.3%	5.9%	77.3%	2.8%	10.6%	1.8%	84.7%	2.0%	5.8%	2.1%	90.1%	5.3%	0.2%	2.6%	91.9%
2017	8.9%	10.4%	6.4%	74.3%	2.1%	10.1%	1.7%	86.2%	1.4%	5.9%	1.9%	90.8%	5.9%	0.4%	2.0%	91.7%
2018	8.3%	11.7%	6.8%	73.2%	1.4%	9.3%	1.4%	87.9%	1.8%	5.6%	1.9%	90.7%	6.2%	0.9%	3.4%	89.6%
2019	7.3%	10.6%	8.0%	74.1%	1.9%	10.4%	1.9%	85.8%	1.8%	6.9%	1.7%	89.7%	7.0%	0.9%	3.0%	89.1%
2020	5.2%	9.0%	9.2%	76.6%	3.9%	8.0%	2.5%	85.6%	4.3%	6.0%	2.0%	87.7%	7.7%	0.1%	3.0%	89.1%
2021	8.0%	14.3%	9.1%	68.5%	2.9%	9.6%	2.4%	85.2%	2.5%	6.0%	3.0%	88.5%	9.3%	0.5%	3.6%	86.6%

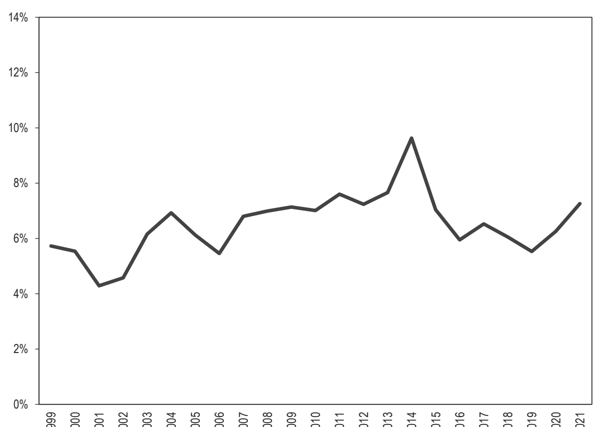
	Hydroelectric				Nuclear				Other			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.3%	7.3%	1.5%	89.9%	1.4%	5.4%	0.3%	93.0%	5.3%	7.1%	3.3%	84.4%
2008	1.4%	8.2%	2.2%	88.3%	1.8%	5.1%	0.8%	92.3%	4.2%	11.0%	3.3%	81.4%
2009	2.4%	8.7%	2.4%	86.5%	4.2%	4.9%	0.6%	90.2%	3.1%	8.0%	5.0%	83.9%
2010	0.7%	8.5%	2.0%	88.9%	2.4%	5.6%	0.5%	91.6%	4.7%	10.5%	3.7%	81.2%
2011	1.6%	12.1%	1.9%	84.4%	2.7%	5.4%	1.2%	90.7%	5.1%	10.8%	3.3%	80.8%
2012	2.9%	5.8%	2.2%	89.1%	1.6%	6.3%	1.0%	91.1%	5.1%	12.0%	4.2%	78.7%
2013	2.3%	8.2%	2.0%	87.5%	0.9%	5.7%	0.6%	92.8%	6.2%	10.7%	3.4%	79.7%
2014	2.6%	9.6%	3.2%	84.6%	1.6%	5.5%	1.0%	92.0%	6.7%	16.2%	5.2%	71.9%
2015	3.9%	9.9%	1.5%	84.6%	1.4%	5.1%	1.4%	92.1%	6.0%	18.1%	4.3%	71.6%
2016	2.7%	7.9%	3.3%	86.2%	1.6%	5.5%	1.1%	91.8%	4.6%	16.6%	4.6%	74.2%
2017	2.4%	5.9%	3.2%	88.5%	0.5%	5.1%	0.7%	93.7%	4.8%	10.1%	5.7%	79.4%
2018	2.7%	7.7%	3.3%	86.4%	0.7%	4.7%	0.6%	94.0%	3.6%	9.1%	8.2%	79.0%
2019	1.6%	7.1%	3.9%	87.5%	0.6%	5.3%	0.9%	93.2%	3.5%	13.5%	6.7%	76.2%
2020	5.7%	6.9%	2.8%	84.6%	1.4%	4.8%	0.7%	93.1%	19.5%	7.8%	5.5%	67.2%
2021	8.5%	7.7%	2.7%	81.0%	1.0%	4.5%	1.1%	93.3%	6.5%	8.5%	6.7%	78.3%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[168] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in 2021 was 7.3 percent, an increase from 6.3 percent in 2020. Figure 5-13 shows the average EFORd since 1999 for all units in PJM.[169]

Figure 5-13 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2021



168 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

169 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2020 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Table 5-31 shows the class average EFORd by unit type.

Table 5-31 EFORd by unit type: 2007 through 2021

	Annual														
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal	8.4%	8.4%	8.2%	9.4%	10.5%	10.1%	10.9%	12.2%	9.4%	9.4%	11.4%	11.0%	10.1%	8.6%	11.8%
Combined Cycle	4.0%	3.8%	4.3%	3.8%	3.5%	4.5%	2.6%	4.6%	3.0%	3.5%	2.7%	2.1%	2.7%	3.9%	3.8%
Combustion Turbine	11.5%	11.7%	10.3%	9.7%	8.7%	8.3%	11.1%	16.5%	9.2%	5.6%	5.4%	6.2%	5.3%	4.3%	5.5%
Diesel	11.7%	10.3%	9.3%	6.4%	9.2%	4.8%	6.6%	15.0%	9.0%	6.9%	7.0%	6.7%	7.6%	7.7%	11.6%
Hydroelectric	2.0%	2.1%	3.3%	1.2%	2.9%	4.5%	3.7%	4.0%	5.5%	3.9%	3.4%	3.5%	2.0%	5.7%	10.7%
Nuclear	1.4%	2.0%	4.3%	2.6%	2.9%	1.8%	1.0%	1.8%	1.5%	1.8%	0.5%	0.8%	0.6%	1.4%	1.1%
Other	9.3%	9.9%	8.4%	7.8%	10.1%	9.0%	10.9%	13.3%	13.2%	9.2%	13.7%	9.2%	9.2%	19.5%	17.3%
Total	6.8%	7.0%	7.2%	7.0%	7.6%	7.2%	7.6%	9.6%	7.0%	6.0%	6.5%	6.1%	5.5%	6.3%	7.3%

EFORd vs EAF

EFORd is not an adequate measure of units' availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. A unit with significant planned and/or maintenance outages is considered to have identical reliability properties in capacity planning, transmission planning and in the sale of capacity in the capacity market.[170] The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

Table 5-32 shows the differences between EFORd and EAF by unit type. For the 2021/2022 Base Residual Auction, total offered UCAP (Unforced Capacity) calculated using the EFORd was 126,452 MW. If EAF were used to calculate available capacity, total available capacity for the 2021/2022 BRA would have been 10.0 percent lower, 114,313 MW.

Table 5-32 EFORd and EAF by unit type: 2012 through 2021

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
Year	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	10.1%	22.6%	4.5%	13.9%	8.3%	7.8%	4.8%	7.0%	4.5%	10.9%	1.8%	8.9%	9.0%	21.3%	7.2%	16.0%
2013	10.9%	23.5%	2.6%	13.4%	11.1%	11.2%	6.6%	7.6%	3.7%	12.5%	1.0%	7.2%	10.9%	20.3%	7.6%	16.3%
2014	12.2%	24.9%	4.6%	15.3%	16.5%	12.6%	15.0%	16.4%	4.0%	15.4%	1.8%	8.0%	13.3%	28.1%	9.6%	18.2%
2015	9.4%	22.3%	3.0%	14.6%	9.2%	9.4%	9.0%	10.7%	5.5%	15.4%	1.5%	7.9%	13.2%	28.4%	7.0%	16.5%
2016	9.4%	22.7%	3.5%	15.3%	5.6%	9.9%	6.9%	8.1%	3.9%	13.8%	1.8%	8.2%	9.2%	25.8%	6.0%	16.3%
2017	11.4%	25.7%	2.7%	13.8%	5.4%	9.2%	7.0%	8.3%	3.4%	11.5%	0.5%	6.3%	13.7%	20.6%	6.5%	16.0%
2018	11.0%	26.8%	2.1%	12.1%	6.2%	9.3%	6.7%	10.4%	3.5%	13.6%	0.8%	6.0%	9.2%	21.0%	6.1%	16.0%
2019	10.1%	25.9%	2.7%	14.2%	5.3%	10.3%	7.6%	10.9%	2.0%	12.5%	0.6%	6.8%	9.2%	23.8%	5.5%	16.5%
2020	8.6%	23.4%	3.9%	13.8%	4.3%	9.6%	7.7%	9.7%	5.7%	13.9%	1.4%	6.8%	19.5%	22.2%	6.3%	15.3%
2021	11.8%	31.5%	3.8%	14.8%	5.5%	11.5%	11.6%	13.4%	10.7%	19.0%	1.1%	6.7%	17.3%	21.7%	7.3%	18.3%
Average	10.5%	24.9%	3.3%	14.1%	7.7%	10.1%	8.3%	10.3%	4.7%	13.9%	1.2%	7.3%	12.4%	23.3%	6.9%	16.5%

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[171] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

170 OATT, Attachment DD (Reliability Pricing Model) § 10A (d).

171 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

The PJM EFOF was 4.5 percent in 2021. Table 5-33 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 18.3 percent of the system EFOF, were the largest single contributor to EFOF.

Table 5-33 Contribution to EFOF by unit type by cause: 2021

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	28.1%	6.4%	0.0%	0.0%	0.0%	0.0%	12.4%	18.3%
Electrical	6.4%	14.5%	9.9%	2.9%	18.5%	22.7%	1.2%	8.7%
Generator	7.8%	16.6%	1.9%	7.7%	2.8%	0.0%	2.4%	7.1%
Turbine	0.0%	0.7%	11.8%	0.0%	70.6%	0.0%	0.0%	6.1%
Unit Testing	2.7%	10.9%	23.5%	27.9%	2.6%	1.4%	6.9%	5.9%
Feedwater System	8.4%	4.5%	0.0%	0.0%	0.0%	3.6%	0.3%	5.6%
Controls	0.8%	3.8%	0.9%	6.6%	0.1%	6.8%	34.4%	4.6%
Boiler Air and Gas Systems	6.5%	0.1%	0.0%	0.0%	0.0%	0.0%	3.1%	4.1%
Wet Scrubbers	5.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
Miscellaneous (Steam Turbine)	2.3%	5.7%	0.0%	0.0%	0.0%	0.0%	1.7%	2.2%
Condensing System	2.6%	0.8%	0.0%	0.0%	0.0%	12.1%	0.3%	2.2%
Auxiliary Systems	0.9%	5.7%	7.3%	0.1%	0.3%	2.5%	0.2%	2.0%
Economic	0.2%	1.4%	1.3%	2.0%	2.1%	0.0%	14.1%	1.9%
Boiler Fuel Supply from Bunkers to Boiler	3.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.8%	1.9%
Miscellaneous (Gas Turbine)	0.0%	2.9%	17.0%	0.0%	0.0%	0.0%	0.0%	1.8%
Circulating Water Systems	2.1%	3.2%	0.0%	0.0%	0.0%	2.8%	0.0%	1.7%
High Pressure Turbine	2.6%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
Boiler Piping System	2.1%	1.3%	0.0%	0.0%	0.0%	0.0%	1.2%	1.5%
Valves	2.1%	1.6%	0.0%	0.0%	0.0%	0.3%	0.6%	1.5%
All Other Causes	15.6%	19.5%	26.5%	52.9%	2.9%	47.7%	20.3%	18.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The PJM EMOF was 4.6 percent in 2021. Table 5-34 shows the causes of EMOF by unit type. Maintenance outages for boiler tube leaks, 10.3 percent of the system EMOF, were the second largest contributor to the system EMOF. Overhauling and inspecting boilers, 12.1 percent of the system EMOF, was the largest contributor to system EMOF. The causes of maintenance outages for diesel and hydroelectric units differed from the other technology types. The largest contributor to EMOF for diesel units and for hydroelectric units was "All Other Causes."

Table 5-34 Contribution to EMOF by unit type by cause: 2021

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Overhaul and Inspections	16.4%	8.3%	0.0%	0.0%	0.0%	0.0%	13.6%	12.1%
Boiler Tube Leaks	14.3%	13.9%	0.0%	0.0%	0.0%	0.0%	3.5%	10.3%
Electrical	5.3%	6.8%	30.6%	1.4%	12.8%	0.0%	6.4%	8.4%
Boiler Air and Gas Systems	10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	6.2%
Miscellaneous (Gas Turbine)	0.0%	18.9%	23.9%	0.0%	0.0%	0.0%	0.0%	4.7%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	76.0%	0.0%	3.9%
Miscellaneous (Balance of Plant)	1.9%	5.2%	3.1%	0.0%	2.5%	0.0%	12.4%	3.4%
Feedwater System	3.1%	0.2%	0.0%	0.0%	0.0%	0.0%	14.1%	3.4%
Auxiliary Systems	3.5%	1.7%	5.6%	0.0%	0.4%	0.0%	3.0%	3.2%
Boiler Piping System	3.4%	8.1%	0.0%	0.0%	0.0%	0.0%	1.1%	3.0%
Precipitators	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%
Wet Scrubbers	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%
Dry Scrubbers	4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%
Condensing System	3.0%	1.5%	0.0%	0.0%	0.0%	0.5%	2.8%	2.3%
High Pressure Turbine	2.8%	0.5%	0.0%	0.0%	0.0%	2.6%	0.6%	1.9%
Circulating Water Systems	1.5%	3.7%	0.0%	0.0%	0.0%	4.8%	2.9%	1.8%
Miscellaneous (Boiler)	1.8%	0.3%	0.0%	0.0%	0.0%	0.0%	4.7%	1.6%
Boiler Tube Fireside Slagging or Fouling	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	1.5%
Fuel, Ignition and Combustion Systems	0.0%	4.3%	9.0%	0.0%	0.0%	0.0%	0.0%	1.5%
All Other Causes	16.1%	26.5%	27.8%	98.5%	84.3%	16.1%	32.8%	22.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 9.2 percent in 2021. Table 5-35 shows the causes of EPOF by unit type. The single largest contributor, 24.7 percent of system EPOF, was planned outages for inspecting and overhauling boilers. The causes of maintenance outages for diesel and hydroelectric units differed from the other technology types. The largest contributor to EPOF for diesel units and for hydroelectric units was "All Other Causes."

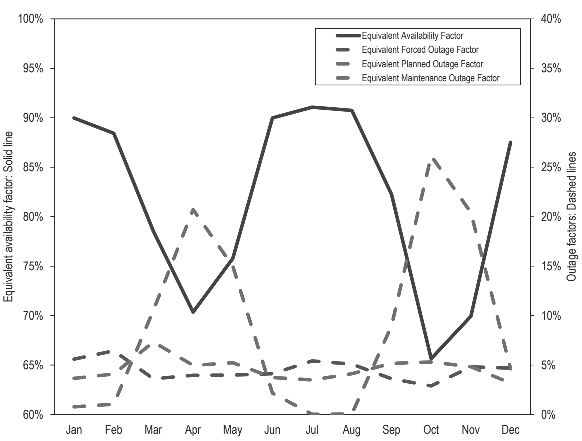
Table 5-35 Contribution to EPOF by unit type and cause: 2021

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Overhaul and Inspections	41.4%	4.0%	0.0%	0.0%	0.0%	0.0%	60.5%	24.7%
Miscellaneous (Gas Turbine)	0.0%	46.3%	55.6%	0.0%	0.0%	0.0%	0.0%	15.5%
Miscellaneous (Balance of Plant)	14.7%	19.0%	11.2%	0.0%	7.0%	0.2%	6.6%	12.9%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	93.5%	0.0%	9.6%
Miscellaneous (Steam Turbine)	5.9%	8.2%	0.0%	0.0%	0.0%	0.0%	0.6%	4.5%
NOx Reduction Systems	5.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%
Electrical	2.3%	1.9%	6.3%	0.5%	0.4%	0.0%	5.7%	2.6%
Boiler Piping System	3.8%	2.3%	0.0%	0.0%	0.0%	0.0%	3.2%	2.5%
Generator	0.0%	1.3%	3.3%	0.0%	35.3%	0.0%	1.1%	2.0%
Boiler Tube Leaks	3.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%	1.6%
Wet Scrubbers	3.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
Low Pressure Turbine	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
Miscellaneous (Generator)	0.7%	1.1%	5.0%	0.0%	2.2%	0.0%	0.7%	1.2%
Boiler Air and Gas Systems	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	1.2%
Miscellaneous (Boiler)	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	16.9%	1.2%
Controls	2.2%	0.1%	0.5%	0.0%	0.0%	0.4%	0.2%	1.2%
Fuel, Ignition and Combustion Systems	0.0%	4.0%	3.3%	0.0%	0.0%	0.0%	0.0%	1.2%
Boiler Tube Fireside Slagging or Fouling	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Condensate System	0.0%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
All Other Causes	10.0%	6.8%	14.6%	99.5%	55.2%	5.9%	3.3%	10.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-14.

Figure 5-14 Monthly generator performance factors: 2021



Generator Testing

PJM's testing requirements are not well designed, permit excessive generator discretion and do not require adequate winter testing. Summer/Winter Capability Testing, also known as Net Capability Verification Testing, is designed to demonstrate whether a resource has the ICAP claimed.[172] Generation owners perform these tests during the summer and winter test periods, but may use data collected in the summer for winter testing after adjusting for ambient winter conditions. Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test. An owner can perform an unlimited number of tests during the testing period before a successful result. Test results must be submitted via eGADS. Generators are required to report failed tests and to derate their unit in eGADS. Failure to report and derate the unit can result in a Generation Resource Rating Test Failure Charge. Generation owners also have the option to buy replacement capacity that satisfies the same locational requirements.[173] [174]

172 "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 51 (Oct. 20, 2021).
173 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 16 (Aug. 1, 2021).
174 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).

Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[1] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

  Total demand response revenue increased by $155.9 million, 43.4 percent, from $359.2 million in 2020 to $515.1 million in 2021. Emergency demand response revenue accounted for 97.9 percent of all demand response revenue, economic demand response for 0.1 percent, demand response in the synchronized reserve market for 1.5 percent and demand response in the regulation market for 0.4 percent.

  Total emergency demand response revenue increased by $149.4 million, 42.1 percent, from $355.1 million in 2020 to $504.4 million in 2021.[2]

  Economic demand response revenue increased by $0.4 million, 128.4 percent, from $0.3 million in 2020 to $0.8 million in 2021.[3] Demand response revenue in the synchronized reserve market increased by $5.2 million, 215.1 percent, from $2.4 million in 2020 to $7.6 million in2021. Demand response revenue in the regulation market increased by $1.0 million, 70.8 percent, from $1.4 million in 2020 to $2.3 million in 2021.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[4]

- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in 2020 and 2021. The HHI for economic resource reductions decreased by 539 points from 9065 for 2020 to 8526 in 2021. The ownership of emergency load response resources was highly concentrated in 2020. The HHI for emergency load response committed MW was 2523 for the 2020/2021 Delivery Year. In the 2020/2021 Delivery Year, the four largest CSPs owned 88.4 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2584 for the 2021/2022 Delivery Year. In the 2021/2022 Delivery Year, the four largest CSPs own 89.0 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. But PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

1 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

2 The total credits and MWh for demand resources were downloaded on January 10, 2022 and may change as a result of continued PJM billing updates.

3 Economic credits are synonymous with revenue received for reductions under the economic load response program.

4 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 85 (Sep. 1, 2021).

Recommendations

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[5] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)

5 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

6 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[7])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the synchronized reserve market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM Capacity Market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations. (Priority: Medium. New recommendation. Status: Not adopted.)

7 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on how customers value the power and on the actual cost of that power.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. PJM automatically, and inappropriately, triggers a PAI when demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance resources.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called when economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

In order to be a substitute for generation, demand resources (DR) should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Interval (PAI) will be measured on a five-minute basis.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative to being a substitute for generation in the capacity and energy markets, demand response resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[8] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[9] [10] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance will be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[11] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE. But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement

8 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.

9 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed March 6, 2019).

10 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (Accessed March 6, 2019).

11 The PJM proposal from the SODRSTF weakened the proposal but was approved at the October 25, 2018 Members Committee meeting and PJM filed Tariff changes on December 7, 2018. See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market. That transition should be defined by the PRD rules, modified as proposed by the MMU.

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in EPSA as it does not depend on whether FERC has jurisdiction over the demand side.[12] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

PJM Demand Response Programs

All PJM demand response programs can be grouped into economic, emergency and pre-emergency programs, or Price Responsive Demand (PRD). Table 6-1 provides an overview of the key features of PJM demand response programs.

Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participate in the capacity market and energy market.[13] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

FERC Order No. 719 required PJM and other RTOs to amend their market rules to accept bids from aggregators of retail customers of utilities unless the laws or regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[14] PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits end use customers' participation.[15] EDCs and their end use customers are categorized as small and large based on whether the EDC distributed more or less than 4 million MWh in the previous fiscal year. End use customers within a large EDC must provide verification of any other contractual obligations or laws or regulations that prohibit participation, but end use customers within a small EDC do not need to provide additional verification.[16] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.

12 577 U.S. 260 (2016).

13 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

14 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), order on reh'g, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

15 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.

16 PJM Operating Agreement Schedule 1 § 1.5A.3.1.

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program	Price Responsive Demand
	Load Management (LM)			Economic Demand Response	
Product Types	Limited, Annual, Base, Capacity Performance, Summer-Period Capacity Performance OATT Attachmend DD § 5.5A	Limited, Annual, Base, Capacity Performance,Summer-Period Capacity Performance OATT Attachmend DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachemnt K § 8.1	Full Program Option (Capacity and Energy) OATT Attachemnt K § 8.1	Energy Only OATT Attachemnt K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	RPM event RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

Non-PJM Demand Response Programs

Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania and North Carolina include demand response in their RPS. If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.

PJM Demand Response Programs

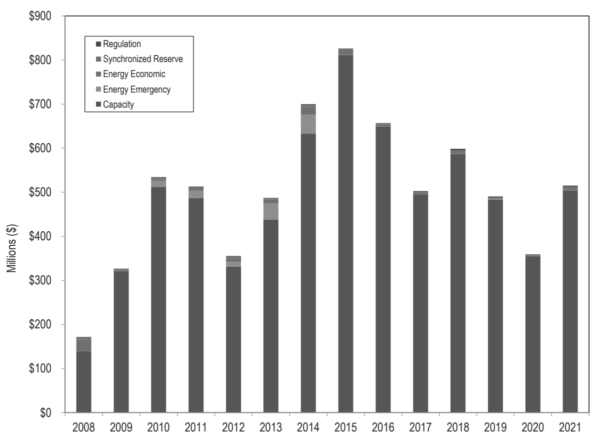
Figure 6-1 shows all revenue from PJM demand response programs by market for 2008 through 2021. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.[17] In 2021, total demand response revenue increased by $155.9 million, 43.4 percent, from $359.2 million in 2020 to $515.1 million in 2021. Total emergency demand response revenue increased by $149.2 million, 42.1 percent, from $355.1 million in 2020 to $504.4 million in 2021. This increase consisted of capacity market revenue.[18] In 2021, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 97.9 percent of all revenue received by demand response providers, the economic program for 0.1 percent, synchronized reserve for 1.5 percent and the regulation market for 0.4 percent.

17 This includes both capacity market revenue and emergency energy revenue for capacity resources.
18 The total credits and MWh for demand resources were downloaded on January 10, 2022 and may change as a result of continued PJM billing updates.

Economic demand response revenue increased by $0.4 million, 128.4 percent, from $0.3 million in 2020 to $0.8 million in2021.[19] Demand response revenue in the synchronized reserve market increased by $5.2 million, 215.1 percent, from $2.4 million in 2020 to $7.6 million in 2021. Demand response revenue in the regulation market increased by $1.0 million, 70.8 percent, from $1.4 million in 2020 to $2.3 million in 2021.

Higher demand resource revenues were in part a result of higher capacity market prices in the 2020/2021 RPM and 2021/2022 RPM auctions compared to capacity market prices in 2019/2020.

Figure 6-1 Demand response revenue by market for 2008 to 2021



Emergency and Pre-Emergency Load Response Programs

Demand resources participate in the capacity market within the Emergency and Pre-Emergency Load Response Programs.

All demand resources must register as pre-emergency unless the participant relies on behind the meter generation and the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[20] Under current rules, PJM will declare an emergency if pre-emergency or emergency demand response is dispatched. In all demand response programs, CSPs are companies that sign up customers that have the ability to reduce load. CSPs satsify cleared RPM commitments registerting customers as Nominated MW. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

The emergency and pre-emergency load response programs consist of the base and capacity performance demand response products. Full implementation of the Capacity Performance design in the 2020/2021 Delivery Year requires all emergency or pre-emergency demand resources to be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.[21]

All capacity resources must respond during a Performance Assessment Interval (PAI). Demand resources are the only capacity performance resource that create a PAI when dispatched by PJM. PJM eliminated any substantive difference between pre-emergency and emergency by making the dispatch of either type trigger a PAI.

The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI unless the product type and lead time type are dispatched by PJM. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI if the area dispatched is not a defined subzone or control zone. Demand resources are not required to meet the same requirements as other capacity resources for the PAI.

Demand resources are also not required to meet the same must offer requirements a other capacity resources. All other capacity resources must offer daily into the day-ahead energy market.

19 Economic credits are synonymous with revenue received for reductions under the economic load response program.
20 OA Schedule 1 § 8.5.
21 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM. *See* PJM OATT RAA Article 1.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the day-ahead energy market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends eliminating the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[22]

Market Structure

The HHI for demand resources showed that ownership was highly concentrated for the 2020/2021 Delivery Year, with an HHI value of 2523. In the 2020/2021 Delivery Year, the four largest companies contributed 88.4 percent of all committed demand resources UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2021/2022 Delivery Year, with an HHI value of 2584. In the 2021/2022 Delivery Year, the four largest companies own 89.0 percent of all committed demand response UCAP MW.

Table 6-2 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

Table 6-2 HHI value for committed UCAP MW by LDA by delivery year: 2020/2021 and 2021/2022 Delivery Years[23]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2020/2021	ATSI	719.8	2488	High
	ATSI-CLEVELAND	231.9	4438	High
	BGE	249.5	2344	High
	COMED	1,657.3	2819	High
	DAY	241.5	3648	High
	DEOK	184.7	3727	High
	DPL-SOUTH	72.6	3807	High
	EMAAC	757.3	2676	High
	MAAC	557.8	2905	High
	PEPCO	236.3	2921	High
	PPL	616.6	2694	High
	PS-NORTH	152.7	3213	High
	PSEG	186.3	2501	High
	RTO	3,581.4	2681	High
2021/2022	ATSI	924.0	2873	High
	ATSI-CLEVELAND	272.8	5910	High
	BGE	279.0	2363	High
	COMED	2,073.7	2769	High
	DAY	227.7	3042	High
	DEOK	220.5	2167	High
	DPL-SOUTH	66.3	5289	High
	EMAAC	904.7	2365	High
	MAAC	750.0	2539	High
	PEPCO	345.9	2625	High
	PPL	697.7	2747	High
	PS-NORTH	188.6	3641	High
	PSEG	221.9	2412	High
	RTO	4,254.9	2874	High

Market Performance

Table 6-3 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM increased by 1,982.0 MW, or 21.0 percent, from 9,445.7 MW in the 2020/2021 Delivery Year to 11,427.7 MW in the 2021/2022 Delivery Year. The DR percent of capacity increased by 1.1 percentage points, from 5.4 percent in the 2020/2021 Delivery Year to 6.5 percent in the 2021/2022 Delivery Year.

22 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

23 The RTO LDA refers to the rest of RTO.

Table 6-3 Cleared Demand Resource UCAP MW: 2007/2008 through 2021/2022 Delivery Year

	UCAP (MW)		
	DR RPM Cleared	Total RPM Cleared	DR Percent Cleared
2007/2008	127.6	129,409.2	0.1%
2008/2009	559.4	130,629.8	0.4%
2009/2010	892.9	134,030.2	0.7%
2010/2011	962.9	134,036.2	0.7%
2011/2012	1,826.6	134,139.6	1.4%
2012/2013	8,740.9	141,061.8	6.2%
2013/2014	10,779.6	159,830.5	6.7%
2014/2015	14,943.0	161,092.4	9.3%
2015/2016	15,453.7	173,487.4	8.9%
2016/2017	13,265.3	179,749.0	7.4%
2017/2018	11,870.5	180,590.3	6.6%
2018/2019	11,435.4	175,957.4	6.5%
2019/2020	10,703.1	177,040.6	6.0%
2020/2021	9,445.7	173,688.5	5.4%
2021/2022	11,427.7	174,713.0	6.5%

Table 6-4 shows zonal monthly capacity market revenue to demand resources for 2021. Capacity market revenue increased in 2021 by $149.4 million, 42.1 percent, from $355.1 million in 2020 to $504.4 million in2021. The capacity revenue amounts for 2020 include five months from the 2019/2020 Delivery Year and seven months from the 2020/2021 delivery year and the capacity revenue amounts for 2021 include five months from the 2020/2021 Delivery Year and seven months from the 2021/2022 Delivery Year.

Table 6-4 Zonal monthly demand resource capacity revenue: 2021

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
ACEC	$364,810	$329,506	$364,810	$353,042	$364,810	$414,657	$428,479	$428,479	$414,657	$428,479	$414,657	$428,479	$4,734,865
AEP, EKPC	$3,309,544	$2,989,265	$3,309,544	$3,202,784	$3,309,544	$7,761,321	$8,020,032	$8,020,032	$7,761,321	$8,020,032	$7,761,321	$8,020,032	$71,484,771
APS	$1,790,204	$1,616,959	$1,790,204	$1,732,456	$1,790,204	$4,296,522	$4,439,739	$4,439,739	$4,296,522	$4,439,739	$4,296,522	$4,439,739	$39,368,550
ATSI	$1,882,518	$1,700,339	$1,882,518	$1,821,792	$1,882,518	$5,909,358	$6,106,337	$6,106,337	$5,909,358	$6,106,337	$5,909,358	$6,106,337	$51,323,107
BGE	$468,186	$422,877	$468,186	$453,083	$468,186	$1,170,553	$1,209,572	$1,209,572	$1,170,553	$1,209,572	$1,170,553	$1,209,572	$10,630,463
COMED	$8,465,782	$7,646,513	$8,465,782	$8,192,692	$8,465,782	$10,830,893	$11,191,922	$11,191,922	$10,830,893	$11,191,922	$10,830,893	$11,191,922	$118,496,919
DAY	$465,983	$420,888	$465,983	$450,951	$465,983	$956,340	$988,218	$988,218	$956,340	$988,218	$956,340	$988,218	$9,091,680
DOM	$1,791,652	$1,618,266	$1,791,652	$1,733,857	$1,791,652	$4,805,706	$4,965,896	$4,965,896	$4,805,706	$4,965,896	$4,805,706	$4,965,896	$43,007,783
DPL	$972,021	$877,954	$972,021	$940,665	$972,021	$1,004,324	$1,037,801	$1,037,801	$1,004,324	$1,037,801	$1,004,324	$1,037,801	$11,898,858
DUKE	$586,115	$529,394	$586,115	$567,208	$586,115	$801,363	$828,075	$828,075	$801,363	$828,075	$801,363	$828,075	$8,571,334
DUQ	$383,237	$346,149	$383,237	$370,874	$383,237	$568,680	$587,636	$587,636	$568,680	$587,636	$568,680	$587,636	$5,923,318
JCPLC	$817,686	$738,555	$817,686	$791,309	$817,686	$846,714	$874,938	$874,938	$846,714	$874,938	$846,714	$874,938	$10,022,816
MEC	$644,939	$582,525	$644,939	$624,134	$644,939	$1,519,890	$1,570,553	$1,570,553	$1,519,890	$1,570,553	$1,519,890	$1,570,553	$13,983,358
PE	$826,762	$746,753	$826,762	$800,092	$826,762	$1,542,009	$1,593,409	$1,593,409	$1,542,009	$1,593,409	$1,542,009	$1,593,409	$15,026,795
PECO	$2,133,013	$1,926,593	$2,133,013	$2,064,206	$2,133,013	$2,219,456	$2,293,438	$2,293,438	$2,219,456	$2,293,438	$2,219,456	$2,293,438	$26,221,961
PEPCO	$432,443	$390,594	$432,443	$418,494	$432,443	$947,100	$978,670	$978,670	$947,100	$978,670	$947,100	$978,670	$8,862,398
PPL	$1,594,416	$1,440,118	$1,594,416	$1,542,983	$1,594,416	$2,884,710	$2,980,867	$2,980,867	$2,884,710	$2,980,867	$2,884,710	$2,980,867	$28,343,948
PSEG	$1,901,994	$1,717,930	$1,901,994	$1,840,640	$1,901,994	$2,503,407	$2,586,854	$2,586,854	$2,503,407	$2,586,854	$2,503,407	$2,586,854	$27,122,191
REC	$22,613	$20,424	$22,613	$21,883	$22,613	$28,837	$29,798	$29,798	$28,837	$29,798	$28,837	$29,798	$315,851
TOTAL	$28,853,918	$26,061,603	$28,853,918	$27,923,146	$28,853,918	$51,011,841	$52,712,236	$52,712,236	$51,011,841	$52,712,236	$51,011,841	$52,712,236	$504,430,968

Pre-Emergency and Emergency Load Response resources must register all resources to respond within 30, 60 or 120 minutes of a PJM dispatched event. The quick lead time, or 30 minute lead time, is the default lead time, unless a CSP submits an exception request for 60 or 120 minute notification time based on a physical constraint.[24] The exception requests must clearly state why the resource is unable to respond within 30 minutes based on the defined reasons for exception listed in Manual 18.[25] Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year. Resources that request longer lead times without a physical constraint are rejected.

Table 6-5 shows the amount of nominated MW and locations by product type and lead time for the 2020/2021 Delivery Year. Nominated MW are Pre-Emergency or Emergency Load Response registrations used to satisfy a CSP's committed MW position for a delivery year. PJM approved 3,096 locations, or 21.2 percent of all locations, which have 3,548.6.0 nominated MW, or 45.0 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2020/2021 Delivery Year.

24 See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 51 (Oct. 20, 2021).
25 See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 49 (Aug. 2021).

Table 6-5 Nominated MW and locations by product type and lead time: 2020/2021 Delivery Year

	Pre-Emergency MW		Emergency MW		
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	4,097.2	4,097.2	240.6	240.6	4,337.9
Short Lead (60 Minutes)	326.9	326.9	28.8	28.8	355.7
Long Lead (120 Minutes)	3,043.0	3,043.0	150.0	150.0	3,192.9
Total	7,467.1	7,467.1	419.4	419.4	7,886.5
	Pre-Emergency Locations		Emergency Locations		
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	11,025	11,025	473	473	11,498
Short Lead (60 Minutes)	316	316	39	39	355
Long Lead (120 Minutes)	2,466	2,466	275	275	2,741
Total	13,807	13,807	787	787	14,594

Table 6-6 shows the amount of nominated MW and locations by product type and lead time for the 2021/2022 Delivery Year. PJM approved 3,208 locations, or 20.9 percent of all locations, which have 3,645.6 nominated MW, or 45.7 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2021/2022 Delivery Year.

Table 6-6 Nominated MW and locations by product type and lead time: 2021/2022 Delivery Year

	Pre-Emergency MW		Emergency MW				
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total	Emergency Total	Total
Quick Lead (30 Minutes)	4,115.5	4,115.5	214.8	214.8	4,330.2	0.0	0.0
Short Lead (60 Minutes)	285.5	285.5	21.0	21.0	306.5	0.0	0.0
Long Lead (120 Minutes)	3,198.2	3,198.2	140.8	140.8	3,339.1	0.0	0.0
Total	7,599.2	7,599.2	376.6	376.6	7,975.8	0.0	0.0
	Pre-Emergency Locations		Emergency Locations				
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total	Emergency Total	Total
Quick Lead (30 Minutes)	11,699	11,699	458	458	12,157	0	0
Short Lead (60 Minutes)	334	334	37	37	371	0	0
Long Lead (120 Minutes)	2,650	2,650	187	187	2,837	0	0
Total	14,683	14,683	682	682	15,365	0	0

There are two ways to measure load reductions of demand resources. The Firm Service Level (FSL) method, applied to the summer, measures the difference between a customer's peak load contribution (PLC) and its real-time load, multiplied by the loss factor (LF).[26] The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[27] With the introduction of the Winter Peak Load (WPL) concept, effective for the 2017/2018 Delivery Year, both the FSL and GLD methods are modified for the non-summer period. The FSL method measures compliance during the non-summer period as the difference between a customer's WPL multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) and the LF, rather than the PLC, and real-time load, multiplied by the LF. PJM calculates and posts on the PJM website the ZWWAF as the zonal winter weather normalized peak divided by the zonal average of the five coincident peak loads in December through February.[28] The Winter Peak Load is adjusted up for transmission and distribution line loss factors because one MW of load would be served by more than one MW of generation to account for transmission losses. The Winter Peak Load is normalized based on the winter conditions during the five coincident peak loads in winter using the ZWWAF to account for an extreme temperatures or a mild winter. The GLD method measures compliance during the non-summer period as the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the WPL multiplied by the ZWWAF and the LF, rather than the PLC, minus the real-time load multiplied by the LF.[29]

26 Real-time load is hourly metered load.

27 135 FERC ¶ 61,212 (2011).

28 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 51 (Oct. 20, 2021).

29 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 51 (Oct. 20, 2021).

The capacity market is an annual market. A Capacity Performance resource has an annual commitment. Load is allocated capacity obligations based on the annual peak load which is a summer load. The amount of MW allocated to load does not vary based on winter demand. The principle is that a customer's actual use of capacity should be compared to the level of capacity that a customer is required to pay for. Capacity costs are allocated to LSEs by PJM based on the single coincident peak load method. In PJM, the single coincident peak occurs in the summer.[30] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[31] The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. If an end customer has 3 MW of load during the coincidental peak load hour, but only 1 MW during the coincidental winter peak load hour, the end use customer must pay for 3 MW of capacity for the entire delivery year, but can only participate as a 1 MW demand response resource. Using PLC to measure compliance the entire delivery year would allow the customer to fully participate as a 3 MW demand response resource. FERC allowed the use of the WPL for calculating compliance for non-summer months effective June 1, 2017.[32] The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

Table 6-7 shows the MW registered by measurement and verification method and by technology type for the 2021/2022 Delivery Year. For the 2021/2022 Delivery Year, 99.98 percent use the FSL method and 0.02 percent use the GLD measurement and verification method.

Table 6-7 Reduction MW by each demand response method: 2021/2022 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,225.2	1,954.3	196.0	689.4	3,851.0	17.7	40.6	7,974.3	99.98%
Guaranteed Load Drop	0.3	1.0	0.0	0.0	0.0	0.0	0.3	1.5	0.02%
Total	1,225.5	1,955.3	196.0	689.4	3,851.0	17.7	40.9	7,975.8	100.0%
Percent by method	15.4%	24.5%	2.5%	8.6%	48.3%	0.2%	0.5%	100.0%	

Table 6-8 shows the fuel type used in the onsite generators for the 2021/2022 Delivery Year in the emergency and pre-emergency programs. For the 2021/2022 Delivery Year, 1,225.5 MW of the 7,975.8 nominated MW, 15.4 percent, used onsite generation. Of the 1,225.5 MW, 84.0 percent used diesel and 16.0 percent used natural gas, gasoline, oil, propane or waste products.

Table 6-8 Onsite generation fuel type (MW): 2021/2022 Delivery Year

	2021/2022	
Fuel Type	MW	Percent
Diesel	1,029.9	84.0%
Natural Gas, Gasoline, Oil, Propane, Waste Products	195.6	16.0%
Total	1,225.5	100.0%

30 OATT Attachment DD.5.11.
31 OATT Attachment M-2.
32 162 FERC ¶ 61,159 (2018).

Table 6-9 shows the MW registered by measurement and verification method and by technology type for the 2020/2021 Delivery Year. For the 2020/2021 Delivery Year, 99.9 percent use the FSL method and 0.1 percent use the GLD measurement and verification method.

Table 6-9 Reduction MW by each demand response method: 2020/2021 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,219.5	1,877.5	196.4	689.8	3,790.6	61.6	44.9	7,880.4	99.9%
Guaranteed Load Drop	0.3	1.1	0.0	0.0	4.4	0.0	0.3	6.1	0.1%
Total	1,219.7	1,878.6	196.4	689.8	3,795.1	61.6	45.2	7,886.5	100.0%
Percent by method	15.5%	23.8%	2.5%	8.7%	48.1%	0.8%	0.6%	100.0%	

Table 6-10 shows the fuel type used in the onsite generators for the 2020/2021 Delivery Year in the emergency and pre-emergency programs. For the 2020/2021 Delivery Year, 1,219.7 MW of the 7,886.5 nominated MW, 15.5 percent, use onsite generation. Of the 1,219.7 MW, 87.0 percent use diesel and 13.0 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-10 Onsite generation fuel type (MW): 2020/2021 Delivery Year

	2020/2021	
Fuel Type	MW	Percent
Diesel	1,061.4	87.0%
Natural Gas, Gasoline, Oil, Propane, Waste Products	158.3	13.0%
Total	1,219.7	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity Performance resources measure performance nodally, except for demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year, if the subzone was defined by PJM no later than the day before the dispatch.[33] A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, the entire registration must respond. PJM does not measure compliance when demand response is dispatched in a subzone created on the same day as the dispatch. Subzonal dispatch creates a PAI for the subzone, even if PJM does not measure compliance for demand resources.

There are currently five dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, and JCPL_REDBANK.[34] Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance, which does not require predefined subzones for mandatory dispatch.[35]

PJM can remove a defined subzone, and make changes to the subzone, at their discretion. Subzones should not be removed once defined, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK subzones were removed by PJM. More subzones may have been removed by PJM but PJM does not keep a record of created and removed subzones. The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response.

The subzone design and closed loop interfaces are related. PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[36] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM

33 OATT Attachment DD, Section 11.

34 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed March 4, 2022).

35 OATT Attachment DD, Section 10A.

36 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software, Docket No. AD10-12-006 (June 23, 2015) <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf>.

also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.[37] The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs.

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes or for a subzone dispatch that was not defined one business day before dispatch, the events are not measured for compliance.

Capacity Performance demand resources currently estimate five minute compliance with an hourly interval meter during PAIs. To accurately measure compliance on a five minute basis, a five minute interval meter is required. All other Capacity Performance resources require five minute interval meters, and demand resources should be no different. Demand resources are paid based on the average performance by registration for the duration of a demand response event. Each capacity performance demand response product should measure compliance on a five minute basis to accurately report reductions during demand response events. The current rules for demand response use the average reduction for the duration of an event. The average duration across multiple hours does not provide an accurate metric for each five minute interval of the event and is inconsistent with the measurement of generation resources. Measuring compliance on a five minute basis would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated on an hourly basis for noncapacity performance resources and on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance.[38]

Under the capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment intervals (PAI).[39] When pre-emergency or emergency demand response is dispatched, a PAI is triggered for PJM. PJM cannot dispatch pre-emergency or emergency demand response without triggering a PAI and measuring compliance. Before PJM created PAI to measure compliance, pre-emergency demand response could be dispatched without calling an emergency event. As a result, PJM now effectively classifies all demand response as an emergency resource.

The MMU recommends that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a performance assessment interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. Table 6-11 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2020/2021 and 2021/2022 Delivery Years. There are 10,283.9 nominated MW of demand response for the 2021/2022 Delivery Year, 51.0 percent of the required reserve margin and 36.7 percent of the actual reserve margin for the 2021/2022 Delivery Year.[40]

37 See the *2018 State of the Market Report for PJM*, Volume 2, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.
38 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 51 (Oct. 20, 2021).
39 OATT § 1 (Performance Assessment Hour).
40 *2021 State of the Market Report for PJM: January through June*, Section 5: Capacity, Table 5-7.

Table 6-11 Demand response nominated MW compared to reserve margin: 2020/2021 and 2021/2022 Delivery Years[41]

Delivery Year	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
2020/2021	8,524.2	21,127.9	40.3%	33,039.8	25.8%
2021/2022	10,283.9	20,176.5	51.0%	28,005.0	36.7%

PJM will dispatch demand resources by zone or subzone for demand resources, or within a PAI area for Capacity Performance resources. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or Emergency Action Area (EAA).[42][43] A CAA, or EAA, is an electrically connected area that has the same capacity market price. This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. With full implementation of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

41 Nominated MW totals are Demand Response ICAP corresponding to Demand Response UCAP cleared in RPM auctions for each delivery year. The total nominated MW values do not reflect replacement transactions.

42 CAA is "a geographic area of Zones or sub-Zones that are electrically contiguous and experience for the relevant Delivery Year, based on Resource Clear Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT § 1.

43 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 51 (Oct. 20, 2021).

Definition of Compliance

Currently, the calculation methods of event and test compliance do not provide reliable results. PJM's interpretation of load management event rules allows over compliance to be reported when there is no actual over compliance. Settlement locations with a negative load reduction value (load increase) are not netted by PJM within registrations or within demand response portfolios. A resource that has load above their baseline during a demand response event has a negative performance value. PJM limits compliance shortfall values to zero MW. This is not explicitly stated in the Tariff or supporting Manuals and the compliance formulas for FSL and GLD customers do allow negative values.[44]

Limiting compliance to only positive values incorrectly calculates compliance. For example, if a registration had two locations, one with a 50 MWh load increase when called, and another with a 75 MWh load reduction when called, PJM calculates compliance for that registration as a 75 MWh load reduction for that event hour. Negative settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would have a calculated 0 MWh reduction in hour one and a 30 MWh reduction in hour two. This has compliance calculated at an average hourly 15 MWh load reduction for that two hour event, compared to a 7.5 MWh observed reduction. Reported compliance is greater than observed compliance, as locations with load increases, i.e. negative reductions, are treated as zero for compliance purposes.

44 OA Schedule 1 § 8.9.

Changing a demand resource compliance calculation from a negative value to 0 MW inaccurately values event performance and capacity performance. Inflated compliance numbers for an event overstates the true value and capacity of demand resources. A demand response capacity resource that performs negatively is also displacing another capacity resource that could supply capacity during a delivery year. By setting the negative compliance value to 0 MW, PJM is inaccurately calculating the value of demand resources.

Load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores such negative reduction values and instead replaces the negative values with a zero MW reduction value. The PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[45] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.

Demand resources that are also registered as economic resources have a calculated CBL for the emergency event days. Demand resources that are not registered as Economic Resources use the three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[46] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage. The MMU recommends the RRMSE test be required for all demand resources with a CBL.

45 OA Schedule 1 § 8.9.
46 157 FERC ¶ 61,067 (2016).

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU recommends capping demand reductions based entirely on behind the meter generation at the lower of economic maximum or actual generation output.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a demand resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[47] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as emergency

47 OA Schedule 1 § 8.2.

or pre-emergency load response customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events. Three proposals that included language to remove bankrupt customers from a CSP's portfolio failed at the June 7, 2017, Market Implementation Committee.[48] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM. The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions so that they can accurately measure compliance.[49]

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment.[50] A CSP picks the testing day, for one hour, on any non-holiday weekday during the applicable mandatory window. A CSP is able to retest if a resource fails to provide the required reduction by less than 25 percent. The ability of CSPs to pick the test time does not simulate emergency conditions. As a result, test compliance is not an accurate representation of the capability of the resource to respond to an actual PJM dispatch of the resource. Given that demand resources are now an annual product, multiple tests are required to ensure reduction capability year round. The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event.

Table 6-12 shows the test penalties by delivery year by product type for the 2016/2017 Delivery Year through the 2020/2021 Delivery Year.[51] The shortfall MW are calculated for each CSP by zone. The weighted rate per MW is the average penalty rate paid per MW. The total penalty column is the sum of the daily test penalties by delivery year and type. The testing window is open through the end of the delivery year.

Table 6-12 Test penalties by delivery year by product type: 2016/2017 through 2020/2021

	2016/2017			2017/2018			2018/2019			2019/2020			2020/2021		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Limited	48.9	$166.41	$2,967,158	13.9	$124.08	$631,665	0.03	$179.80	$2,100						
Extended Summer	7.3	$138.14	$370,290	10.5	$142.86	$547,928									
Annual	4.8	$137.45	$241,406	16.3	$144.00	$855,940									
Base DR and EE							16.3	$186.80	$1,110,134	30.2	$154.69	$1,712,177			
Capacity Performance	2.1	$160.80	$124,310	0.6	$181.80	$40,146	2.6	$188.55	$178,795				0.9	$125.30	$39,422
Total	63.1	$160.72	$3,703,163	41.3	$137.54	$2,075,678	18.9	$187.03	$1,291,030	30.2	$154.69	$1,712,177	0.9	$125.30	$39,422

48 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Approved Minutes from the Market Implementation Committee*, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx>.

49 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

50 The mandatory response time for Capacity Performance DR is June through October and the following May between 10:00AM to 10:00PM EPT and November through April between 6:00AM through 9:00PM EPT. *See* PJM. "Manual 18: PJM Capacity Market," Rev. 51 (Oct. 20, 2021).

51 Not all products received penalties or existed in every delivery year. For example, the Base and Capacity Performance products were not an option for the 2020/2021 Delivery Year.

Emergency and Pre-Emergency Load Response Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[52] There are 98.1 percent of nominated MW for the 2021/2022 Delivery Year registered under the full program option. There are 1.9 percent of nominated MW for the 2021/2022 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only: "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets."[53] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2021/2022 Delivery Year.[54] [55] Demand resources registered with the full option should be required to verify energy offers in excess of $1,000 per MWh. PJM does not require such verification.[56] The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the synchronized reserve market, but not demand resources or economic resources.[57]

Table 6-13 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2020/2021 Delivery Year. The majority of participants, 76.2 percent of locations and 52.8 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2020/2021 Delivery Year. Almost all registrations, 98.3 percent of locations and 97.1 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $156.16 per location and $137.58 per nominated MW.

Table 6-13 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2020/2021 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	243	1.7%	222.4	2.9%	$68.14	$30.96
$1,000-$1,275	2,763	19.5%	3,102.7	39.9%	$156.16	$137.58
$1,275-$1,550	356	2.5%	345.0	4.4%	$53.78	$55.49
$1,550-$1,849	10,792	76.2%	4,099.2	52.8%	$55.80	$146.91
Total	14,154	100.0%	7,769.3	100.0%	$75.55	$137.65

Table 6-14 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2021/2022 Delivery Year. The majority of participants, 77.4 percent of locations and 52.2 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the

52 *Id.*
53 161 FERC ¶ 61,153 at P 8 (2017).
54 139 FERC ¶ 61,057 (2012).
55 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
56 OATT Attachment K Appendix Section 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).
57 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 39 (Jan. 18, 2022).

maximum price allowed for the 2021/2022 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.3 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $162.68 per location and $143.75 per nominated MW.

Table 6-14 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2021/2022 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	107	0.7%	207.8	2.7%	$97.45	$20.58
$1,000-$1,275	2,898	19.4%	3,214.4	41.3%	$162.68	$143.75
$1,275-$1,550	370	2.5%	295.3	3.8%	$43.71	$54.76
$1,550-$1,849	11,529	77.4%	4,059.1	52.2%	$50.71	$144.03
Total	14,904	100.0%	7,776.7	100.0%	$72.64	$139.22

PRD

The PRD rules are more aligned with the Capacity Performance construct effective December 30, 2019, although the rules still fall short.[58] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[59] PJM's final filing adopted the MMU's recommendation to exclude the use of Winter Peak Load (WPL) when calculating the nominated MW for PRD resources used to satisfy RPM commitments. Load is allocated capacity obligations based on the annual peak load within PJM. The amount of capacity allocated to load is a function solely of summer coincident peak demand and is unaffected by winter demand. Use of the WPL to calculate the nominated MW for PRD resources to satisfy RPM commitments, would incorrectly restrict PRD to less than the total capacity the customer is required to buy. PJM's adoption of the MMU recommendation will correctly value PRD nominated MW. FERC required and PJM's filing also adopted, the MMU's recommendation that PRD should be eligible for bonus performance payments during Performance Assessment Intervals (PAI) only when PRD resources respond above their nominated MW value. Allowing PRD resources to collect bonus payments at times when they are not even required to meet their basic obligation would be inconsistent with the basic CP construct as it applies to all other CP resources.[60]

PJM's filing still fell short of completely aligning PRD with the Capacity Performance product. PRD resources will not have to respond during a PAI if the PAI's trigger price is above LMP during the PAI. All other CP resources have the obligation to perform during a PAI, regardless of the real-time LMP, subject to instructions from PJM. PRD should be held to the same standard during a PAI event.

PRD does not receive direct capacity or energy payments. PRD reduces the amount of capacity that must be purchased by the LSE and therefore reduces the LSE's payments for capacity. When PRD load is not on the system, that load also avoids paying for the associated energy. PRD meets its obligation by responding when LMP is at or above price thresholds defined in the PRD plan.[61] PRD does not have to respond during performance assessment intervals (PAI) and therefore is inferior to other capacity resources and is not a substitute for other capacity resources in the capacity performance construct. The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year, and cleared for the 2021/2022 Delivery Year and 2022/2023 Delivery Year.[62]

Economic Load Response Program

The Economic Load Response Program is for demand response customers that offer into the day-ahead or real-time energy market. The estimated load reduction is paid the zonal LMP, as long as the zonal LMP is greater than the monthly Net Benefits Test threshold.

Market Structure

Table 6-15 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2020, through December 31, 2021. The ownership of economic

58 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).
59 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).
60 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).
61 The Demand Response Subcommittee (DRS) is currently working to align PRD with the CP designed products.
62 There were a total of 558 MW of cleared PRD in the 2020/2021 Delivery Year. See PJM Auction Results, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-results.ashx?la=en>.

demand response resources was highly concentrated in 2020 and 2021.[63] Table 6-15 lists the share of reported reductions provided by, and the share of credits claimed by the four largest CSPs in each year. In 2021, 70.1 percent of all economic DR reported reductions and 65.2 percent of economic DR revenue were attributable to the four largest CSPs. The HHI for economic demand response was highly concentrated for 2021. The annual HHI for economic demand response decreased by 539 from 9065 for 2020 to 8526 for 2021.

Table 6-15 Average hourly MWh HHI and market concentration in the economic program: January 2020 through December 2021[64]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	2020	2021	Percent Change	2020	2021	Change in Percent	2020	2021	Change in Percent
Jan	8983	9305	3.6%	98.1%	99.3%	1.2%	98.3%	98.6%	0.3%
Feb	9652	7601	(21.3%)	100.0%	92.8%	(7.2%)	100.0%	90.5%	(9.5%)
Mar	9857	9700	(1.6%)	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
Apr	10000	9339	(6.6%)		100.0%			100.0%	
May	9926	9732	(2.0%)		100.0%			100.0%	
Jun	8976	8087	(9.9%)	100.0%	88.6%	(11.4%)	99.9%	83.6%	(16.3%)
Jul	8442	8238	(2.4%)	88.8%	91.5%	2.7%	90.2%	90.1%	(0.1%)
Aug	8344	8121	(2.7%)	93.5%	89.1%	(4.5%)	93.1%	90.1%	(3.0%)
Sep	8893	7940	(10.7%)	100.0%	95.3%	(4.7%)	100.0%	96.3%	(3.7%)
Oct	9400	8803	(6.4%)		96.9%			96.1%	
Nov	8121	8914	9.8%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
Dec	7745	9596	23.9%		100.0%			100.0%	
Total	9065	8526	(6.0%)	82.3%	70.1%	(12.2%)	82.8%	65.2%	(17.6%)

Market Performance

Table 6-16 shows the total MW reported reductions made by participants in the economic program and the total credits paid for these reported reductions in 2010 through 2021. The average credits per MWh paid increased by $25.01 per MWh, 70.0 percent, from $35.72 per MWh in 2020 to $60.73 per MWh in 2021. The PJM real-time load-weighted average LMP in 2021 increased 82.8 percent from 2020, from $21.77 per MWh to $39.78 per MWh. Curtailed energy for the economic program increased by 9,527 MWh, 103.4 percent, from 9,213 MWh in 2020 to 18,740 MWh in 2021. Total credits paid for the economic load response program in 2021 increased by $0.8 million, 245.8 percent, from $0.3 million in 2020 to $1.1 million in 2021.

Table 6-16 Credits paid to economic program participants: 2010 through 2021

	Total MWh	Total Credits	$/MWh
2010	72,757	$3,088,049	$42.44
2011	17,398	$2,052,996	$118.00
2012	144,285	$9,278,942	$64.31
2013	133,963	$8,711,873	$65.03
2014	146,301	$17,820,063	$121.80
2015	121,129	$7,983,488	$65.91
2016	81,908	$3,550,535	$43.35
2017	62,622	$2,709,335	$43.27
2018	49,441	$2,548,575	$51.55
2019	24,306	$979,348	$40.29
2020	9,213	$329,119	$35.72
2021	18,740	$1,138,038	$60.73

Economic demand response resources that are dispatched by PJM in both the economic and emergency programs are paid the higher price defined in the emergency rules.[65] For example, assume a demand resource has an economic offer price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the day-ahead energy market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear.[66] All other resources that clear in the day-ahead market are financially firm at the clearing price. Payment at a guaranteed strike price and the ability to set energy market prices at the strike price effectively grant the seller the right to exercise market power.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 1, 2010, through December 31, 2021.

63 All HHI calculations in this section are at the parent company level.
64 April, May, October and December 2020 reduction and credit share values, and March and April 2021 reduction and credit share values are redacted based on confidentiality rules.
65 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 117 (Nov. 1, 2021).
66 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016) ("Order No. 831").

Figure 6-2 Economic program credits and MWh by month: 2010 through 2021

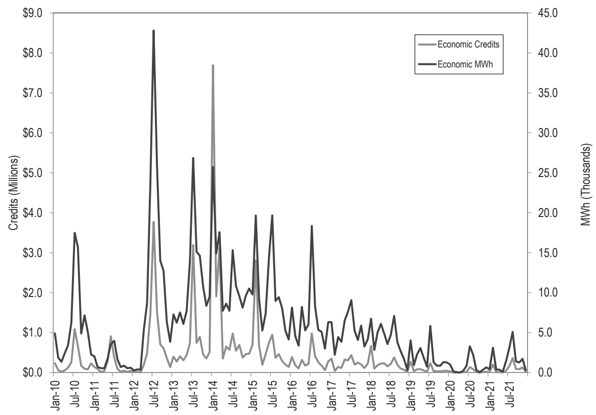


Table 6-17 shows performance for 2020 and 2021 in the economic program by control zone. Total reported reductions under the economic program increased by 8,344 MWh, 122.8 percent, from 6,796 MWh in 2020 to 15,140 MWh in 2021. Total revenue under the economic program increased by $0.7 million, 273.4 percent, from $0.3 million in2020 to $0.9 million in 2021.[67]

Emergency and economic demand response energy payments are uplift and not compensated by LMP revenues. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[68] The zonal allocation is shown in Table 6-17.

Table 6-17 Economic program participation by zone: 2020 and 2021

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2020	2021	Percent Change	2020	2021	Percent Change	2020	2021	Percent Change
ACEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	$880.95	$378,207.22	42,831.7%	18	5,979	33,123.1%	$48.95	$63.26	29.2%
APS	$12,356.22	$13,965.80	13.0%	210	197	(6.3%)	$58.74	$70.88	20.7%
ATSI	$26,170.70	$29,286.94	11.9%	302	358	18.6%	$86.77	$81.85	(5.7%)
BGE	$0.00	$50,122.22	NA	0	641	NA	NA	$78.18	NA
COMED	$125,412.82	$32,908.38	(73.8%)	3,899	643	(83.5%)	$32.16	$51.16	59.0%
DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	$0.00	$232.58	NA	0	0	NA	NA	NA	NA
DOM	$2,226.86	$10,465.15	370.0%	46	80	71.8%	$48.10	$131.56	173.5%
DPL	$10,800.39	$28,300.73	162.0%	138	522	278.7%	$78.37	$54.23	(30.8%)
JCPLC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
MEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$27,814.61	$153,641.75	452.4%	589	2,655	350.5%	$47.20	$57.86	22.6%
PE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PEPCO	$97.49	$16,841.27	17,174.9%	2	297	18,305.1%	$60.39	$56.68	(6.1%)
PPL	$3,716.95	$130,792.33	3,418.8%	76	2,255	2,880.2%	$49.12	$58.00	18.1%
PSEG	$42,086.74	$94,578.87	124.7%	1,516	1,513	(0.2%)	$27.76	$62.52	125.2%
REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	$251,563.73	$939,343.24	273.4%	6,796	15,140	122.8%	$37.02	$62.05	67.6%

67 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-17. Payments for Economic demand response reductions are settled monthly.

68 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 85 (Sep. 1, 2021).

Table 6-18 shows average reported MWh reductions and credits by hour for 2020 and 2021. The average LMP during Load Response is the reduction weighted average hourly DA or RT load weighted LMP during the economic load response hour. In 2020, 97.2 percent of the reported reductions and 96.5 percent of credits occurred in hours ending 0900 to 2100, and in 2021, 89.1 percent of the reported reductions and 89.7 percent of credits occurred in hours ending 0900 to 2100.

Table 6-18 Hourly frequency distribution of economic program reported MWh reductions and credits: 2020 and 2021

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2020	2021	Percent Change	2020	2021	Percent Change	2020	2021	Percent Change
1 through 6	7	472	6,985%	$264	$26,363	9,885%	$37.30	$62.05	66%
7	30	281	825%	$1,360	$18,327	1,248%	$40.03	$76.25	90%
8	141	372	164%	$5,996	$24,092	302%	$41.52	$87.98	112%
9	212	604	185%	$6,756	$32,847	386%	$29.85	$63.93	114%
10	242	635	162%	$7,195	$31,153	333%	$27.49	$54.35	98%
11	258	699	171%	$6,895	$33,315	383%	$27.86	$54.14	94%
12	555	823	48%	$15,191	$39,936	163%	$27.68	$52.75	91%
13	764	931	22%	$21,137	$47,189	123%	$29.83	$55.76	87%
14	907	1,321	46%	$29,694	$77,558	161%	$33.51	$62.58	87%
15	1,084	1,462	35%	$36,260	$86,863	140%	$37.03	$63.05	70%
16	1,101	1,748	59%	$38,897	$120,773	210%	$38.37	$68.25	78%
17	1,251	2,112	69%	$51,157	$153,604	200%	$43.03	$77.13	79%
18	1,226	2,614	113%	$56,196	$165,633	195%	$43.50	$82.22	89%
19	969	1,598	65%	$36,483	$111,456	206%	$36.19	$74.40	106%
20	258	1,237	380%	$7,610	$70,336	824%	$28.32	$63.26	123%
21	127	910	617%	$4,013	$50,006	1,146%	$27.75	$58.50	111%
22	52	546	943%	$2,818	$28,672	917%	$29.24	$55.87	91%
23 through 24	29	376	1,184%	$1,197	$19,912	1,563%	$24.62	$105.70	329%
Total	9,213	18,740	103%	$329,119	$1,138,038	246%	$33.51	$67.68	106%

Table 6-19 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in 2020 and 2021. In 2021, 1.8 percent of reported MWh reductions and 2.5 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-19 Frequency distribution of economic program zonal load-weighted average LMP (By hours): 2020 and 2021

	MWh Reductions			Program Credits		
LMP	2020	2021	Percent Change	2020	2021	Percent Change
$0 to $25	3,697	980	(73%)	$96,190	$27,120	(72%)
$25 to $50	4,193	8,158	95%	$153,988	$390,466	154%
$50 to $75	759	5,532	628%	$34,543	$354,493	926%
$75 to $100	189	1,817	863%	$5,567	$150,693	2,607%
$100 to $125	168	1,375	718%	$10,447	$144,507	1,283%
$125 to $150	68	342	404%	$8,792	$31,725	261%
$150 to $175	46	207	353%	$3,368	$10,850	222%
> $175	93	329	253%	$16,223	$28,184	74%
Total	9,213	18,740	103%	$329,119	$1,138,038	246%

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-20 shows the sum of real-time and day-ahead Economic Load Response charges paid in each zone and paid by exports. Real-time loads in AEP paid the highest Economic Load Response charges in 2021.

Table 6-20 Zonal Economic Load Response charge: 2021[69]

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
ACEC	$142	$2,082	$75	$28	$34	$1,005	$2,485	$5,616	$1,275	$1,012	$1,482	$135	$15,371
AEP	$2,443	$30,173	$1,562	$1,987	$683	$10,648	$22,654	$50,098	$13,673	$12,720	$21,112	$2,537	$170,291
APS	$980	$12,123	$672	$476	$262	$4,296	$8,892	$19,835	$5,158	$4,798	$8,386	$1,021	$66,899
ATSI	$1,214	$14,678	$878	$1,092	$357	$6,006	$12,324	$27,841	$7,274	$6,805	$10,546	$1,229	$90,243
BGE	$586	$7,600	$635	$494	$156	$3,011	$6,543	$14,407	$3,634	$3,131	$5,007	$635	$45,840
COMED	$1,578	$21,412	$829	$1,115	$484	$7,775	$18,880	$43,052	$10,981	$9,707	$12,662	$1,430	$129,905
DAY	$329	$4,140	$268	$348	$95	$1,563	$3,282	$7,299	$1,941	$1,797	$2,839	$344	$24,244
DUKE	$499	$6,349	$326	$427	$146	$2,479	$5,236	$11,694	$3,072	$2,761	$4,188	$511	$37,689
DUQ	$241	$2,937	$140	$212	$77	$1,301	$2,644	$5,880	$1,506	$1,392	$2,073	$240	$18,643
DOM	$2,135	$25,913	$1,612	$1,655	$554	$9,738	$21,178	$46,654	$12,336	$11,152	$17,836	$2,208	$152,971
DPL	$313	$4,634	$199	$584	$66	$1,714	$4,081	$8,788	$2,177	$1,828	$2,818	$314	$27,515
EKPC	$273	$3,854	$161	$190	$62	$1,091	$2,366	$5,440	$1,363	$1,249	$2,354	$269	$18,673
JCPLC	$298	$4,851	$186	$68	$104	$2,567	$5,467	$12,749	$2,798	$2,216	$3,457	$381	$35,141
MEC	$243	$3,719	$153	$151	$79	$1,403	$3,027	$6,910	$1,758	$1,553	$2,617	$322	$21,936
OVEC	$2	$28	$1	$2	$0	$7	$15	$34	$10	$11	$19	$2	$132
PECO	$606	$9,083	$315	$132	$144	$3,708	$8,245	$18,667	$4,605	$3,863	$5,770	$610	$55,747
PE	$333	$4,001	$197	$130	$90	$1,412	$2,906	$6,618	$1,752	$1,741	$2,885	$347	$22,411
PEPCO	$488	$6,970	$510	$405	$149	$2,779	$5,947	$12,870	$3,349	$2,936	$4,498	$565	$41,465
PPL	$658	$10,063	$335	$284	$200	$3,502	$7,524	$16,917	$4,345	$3,986	$6,947	$857	$55,618
PSEG	$785	$9,360	$425	$133	$198	$4,398	$9,295	$21,469	$5,176	$4,322	$6,604	$715	$62,879
REC	$25	$292	$14	$4	$8	$184	$356	$842	$183	$144	$215	$24	$2,291
Exports	$681	$18,547	$931	$2,184	$175	$3,832	$8,946	$18,386	$3,918	$3,941	$4,752	$918	$67,210
Total	$14,851	$202,811	$10,424	$12,098	$4,122	$74,417	$162,294	$362,067	$92,286	$83,066	$129,066	$15,612	$1,163,113

Table 6-21 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in 2021.

Table 6-21 Zonal economic load response charge per GWh of load and exports: 2021

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$0.178	$2.826	$0.110	$1.365	$0.048	$1.073	$2.127	$4.824	$1.452	$1.403	$2.114	$0.176	$1.556
AEP	$0.211	$2.800	$0.156	$1.320	$0.072	$1.010	$2.004	$4.284	$1.384	$1.354	$2.105	$0.242	$1.471
APS	$0.212	$2.837	$0.170	$1.348	$0.072	$1.073	$2.071	$4.469	$1.403	$1.353	$2.129	$0.245	$1.517
ATSI	$0.216	$2.768	$0.172	$1.332	$0.072	$1.052	$2.037	$4.375	$1.392	$1.352	$2.082	$0.229	$1.491
BGE	$0.208	$2.907	$0.271	$1.406	$0.071	$1.109	$2.106	$4.653	$1.468	$1.421	$2.163	$0.253	$1.578
COMED	$0.201	$2.814	$0.118	$1.291	$0.070	$0.894	$2.059	$4.378	$1.411	$1.375	$1.810	$0.191	$1.471
DAY	$0.216	$2.848	$0.203	$1.364	$0.074	$1.067	$2.071	$4.418	$1.436	$1.382	$2.114	$0.248	$1.522
DUKE	$0.216	$2.883	$0.164	$1.357	$0.073	$1.054	$2.051	$4.434	$1.427	$1.397	$2.110	$0.244	$1.518
DUQ	$0.216	$2.839	$0.141	$1.352	$0.075	$1.101	$2.067	$4.435	$1.425	$1.390	$2.078	$0.227	$1.517
DOM	$0.220	$2.887	$0.198	$1.362	$0.070	$1.052	$2.032	$4.462	$1.417	$1.400	$2.127	$0.249	$1.522
DPL	$0.183	$2.903	$0.142	$1.395	$0.050	$1.054	$2.120	$4.690	$1.463	$1.422	$2.028	$0.208	$1.555
EKPC	$0.200	$2.952	$0.158	$1.390	$0.069	$1.096	$2.088	$4.673	$1.426	$1.361	$2.184	$0.264	$1.561
JCPLC	$0.159	$2.807	$0.115	$1.431	$0.065	$1.215	$2.258	$5.216	$1.505	$1.404	$2.166	$0.216	$1.641
MEC	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
OVEC	$0.194	$2.667	$0.131	$1.168	$0.058	$0.823	$1.682	$3.669	$1.197	$1.221	$1.988	$0.217	$1.288
PECO	$0.178	$2.875	$0.105	$1.345	$0.051	$1.066	$2.081	$4.723	$1.449	$1.379	$1.994	$0.194	$1.541
PE	$0.217	$2.825	$0.140	$1.311	$0.071	$1.019	$1.994	$4.333	$1.354	$1.327	$2.103	$0.242	$1.474
PEPCO	$0.194	$2.955	$0.242	$1.391	$0.073	$1.108	$2.080	$4.528	$1.454	$1.433	$2.152	$0.253	$1.558
PPL	$0.171	$2.853	$0.099	$1.336	$0.067	$1.041	$2.053	$4.524	$1.406	$1.351	$2.126	$0.244	$1.506
PSEG	$0.221	$2.854	$0.134	$1.368	$0.064	$1.109	$2.092	$4.757	$1.436	$1.369	$2.123	$0.211	$1.559
REC	$0.223	$2.854	$0.138	$1.456	$0.075	$1.273	$2.304	$5.324	$1.499	$1.387	$2.128	$0.222	$1.683
Exports	$0.216	$3.660	$0.280	$1.353	$0.063	$0.875	$1.951	$4.169	$1.104	$1.209	$1.802	$0.180	$1.519
Monthly Average	$0.193	$2.755	$0.154	$1.293	$0.064	$1.008	$1.969	$4.334	$1.341	$1.304	$1.983	$0.216	$1.457

69 Load response charges were downloaded March 4, 2022 and may change as a result of continued PJM billing updates.

Table 6-22 shows the monthly day-ahead and real-time Economic Load Response charges for 2020 and 2021. The day-ahead Economic Load Response charges increased by $552.8 thousand, 219.0 percent, from $252.4 thousand in 2020 to $805.2 thousand in2021. The real-time Economic Load Response charges increased $256.1 thousand, 333.9 percent, from $76.7 thousand in 2020 to $332.8 thousand in 2021.

Table 6-22 Monthly day-ahead and real-time economic load response charge: 2020 through 2021

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	2020	2021	Percent Change	2020	2021	Percent Change
Jan	$28,908	$14,204	(50.9%)	$1,391	$648	(53.5%)
Feb	$2,317	$160,337	6,821.1%	$335	$42,474	12,591.2%
Mar	$936	$10,287	999.3%	$237	$136	(42.6%)
Apr	$0	$8,332	NA	$197	$3,766	1,814.3%
May	$4,315	$2,060	(52.3%)	$1,846	$2,062	11.7%
Jun	$11,138	$37,802	239.4%	$5,458	$11,412	109.1%
Jul	$87,384	$120,863	38.3%	$49,176	$41,559	(15.5%)
Aug	$70,100	$178,881	155.2%	$14,727	$183,186	1,143.9%
Sep	$10,140	$80,272	691.6%	$525	$12,014	2,188.3%
Oct	$1,694	$64,685	3,717.9%	$331	$18,381	5,457.1%
Nov	$10,064	$115,233	1,044.9%	$1,596	$13,833	766.6%
Dec	$25,410	$12,238	(51.8%)	$894	$3,373	277.5%
Total	$252,407	$805,194	219.0%	$76,712	$332,843	333.9%

Table 6-23 shows registered sites and MW for the last day of each month for the period January 1, 2015, through December 31, 2021. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations decreased by 7, 2.3 percent, from 316 in 2020 to 309 in 2021. Average monthly registered MW decreased by 114 MW, 5.6 percent, from 2,040 MW in 2020 to 1927 MW in 2021.

Most economic demand response resources are registered in the emergency demand response program. Resources registered in both programs do not need to register for the same amount of MW. There are 85 economic registrations and 92 capacity registrations in the emergency program that share the same location ids in both programs. There are 1,013 nominated economic MW and 796 nominated capacity MW in the emergency program that share the same location ids in both programs

Table 6-23 Economic program registrations on the last day of the month: 2015 through 2021[70]

	2015		2016		2017		2018		2019		2020		2021	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,078	2,960	838	2,557	871	2,603	537	2,570	374	2,651	377	2,909	277	1,495
Feb	1,076	2,956	835	2,557	842	2,578	537	2,628	370	2,640	382	2,912	275	1,503
Mar	1,075	2,949	834	2,556	850	2,576	519	2,641	378	2,648	380	2,941	284	1,514
Apr	1,076	2,938	832	2,556	897	2,574	501	2,624	366	2,594	350	2,917	293	1,538
May	980	2,846	829	2,545	977	2,626	471	2,615	372	3,193	308	2,824	319	1,658
Jun	871	2,614	518	2,500	577	1,305	397	2,576	370	2,768	285	1,418	313	2,136
Jul	870	2,609	519	2,421	589	1,548	374	2,591	376	2,899	283	1,453	312	2,105
Aug	869	2,609	805	2,569	590	1,541	382	2,609	360	2,885	292	1,482	322	2,122
Sep	867	2,608	831	2,608	588	1,663	378	2,580	368	2,954	297	1,566	322	2,256
Oct	858	2,568	822	2,564	574	1,660	382	2,584	375	2,909	275	1,361	332	2,267
Nov	851	2,566	820	2,564	559	1,662	381	2,581	379	3,051	280	1,375	333	2,270
Dec	850	2,566	807	2,561	556	1,659	392	2,671	383	3,070	282	1,327	320	2,256
Avg	974	2,788	774	2,547	706	2,000	438	2,606	373	2,855	316	2,040	309	1,927

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch up to the amount of MW registered in the program, but are not required to offer any MW. Table 6-24 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010, through December 31, 2021. The monthly peak is the sum of each registration's monthly noncoincident peak dispatched MW and annual peak is the sum of each registration's annual noncoincident peak

70 Data for years 2010 through 2014 are available in the *2018 State of the Market Report for PJM.*

dispatched MW. The peak dispatched MW for all economic demand response registered resources increased by 724.9 MW, 370.1 percent, from 195.9 MW 2020 to 920.8 MW in 2021.[71] The largest monthly peak MW reduction in 2021, 827 MW in August, was 1,100 MW less than the average MW registered in 2021, 1,927 MW.

Table 6-24 Sum of peak MW reported reductions for all registrations per month: 2010 through 2021

Sum of Peak MW Reductions for all Registrations per Month												
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jan	183	132	110	193	446	169	139	123	142	88	28	21
Feb	121	89	101	119	307	336	128	83	70	58	11	86
Mar	115	81	72	127	369	198	120	111	71	38	12	20
Apr	111	80	108	133	146	143	118	54	71	41	3	22
May	172	98	143	192	151	161	131	169	70	22	12	9
Jun	209	561	954	433	483	833	121	240	105	26	38	125
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518	770	135	134
Aug	794	161	952	497	358	272	249	141	581	33	99	827
Sep	276	84	451	530	795	816	263	140	112	76	31	35
Oct	118	81	242	168	214	136	150	88	69	29	9	31
Nov	111	86	165	155	166	127	116	81	54	35	12	31
Dec	114	88	98	168	155	122	147	83	11	31	14	19
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	758	830	196	921

Table 6-25 shows total settlements submitted for 2010 through 2021. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-25 Settlements submitted in the economic program: 2010 through 2021

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Number of Settlements	3,781	732	5,835	2,846	3,014	2,173	1,958	1,884	1,524	1,066	520	931

Table 6-26 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for 2010 through 2021. The number of active participants increased by 8, 27.6 percent, from 29 in 2020 to 37 in 2021. All participants must be registered through a CSP.

Table 6-26 Participants and CSPs submitting settlements in the economic program by year: 2010 through 2021

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Active CSPs	16	15	22	20	18	18	12	13	14	13	11	11
Active Participants	258	203	428	276	165	116	58	72	59	53	29	37

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[72] Economic resources offer into the energy market and must provide supporting documentation to offer above $1,000 per MWh. FERC stated, "[t]he offer cap reforms, however, do not apply to capacity-only demand response resources that do not submit incremental energy offers into energy markets."[73] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of FERC Order No. 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff

71 Peak MW reductions were downloaded on March 4, 2022 and may change as a result of continued PJM billing updates.
72 157 FERC ¶ 61,115 at P 139 (2016).
73 *Id.* at 8.

rates. Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load. PJM calculates the NBT price threshold by first taking the generation offers from the same month of the previous year. For example, the NBT price calculation for February 2017 was calculated using generation offers from February 2016. PJM then adjusts these offers to account for changes in fuel prices and uses these adjusted offers to create an average monthly supply curve. PJM estimates a function that best fits this supply curve and then finds the point on this curve where the elasticity is equal to one.[74] The price at this point is the NBT threshold price.

The NBT test is a crude tool that is not based in market logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate real-time or day-ahead prices. In addition, it is a single threshold price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location and regardless of locational prices.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

When the zonal LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full zonal LMP. When the zonal LMP is below the NBT threshold price, economic demand response resources are not paid for any load reported reductions.

Table 6-27 shows the NBT threshold price for the historical test from August 2010 through July 2011, and April 2012, when FERC Order No. 745 was implemented in PJM, through December 2021. The historical test was used as justification for the method of calculating the NBT for future months. The NBT threshold price has exceeded the lowest historical test result of $34.07 per MWh one time, in March 2014 when the NBT threshold price was $34.93.

Table 6-27 Net benefits test threshold prices: August 2010 through December 2021

	Historical Test ($/MWh)		Net Benefits Test Threshold Price ($/MWh)									
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jan		$40.27		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44	$20.04	$18.11
Feb		$40.49		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65	$23.49	$19.29	$18.70
Mar		$38.48		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15	$17.44	$20.82
Apr		$36.76	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36	$15.91	$23.47
May		$34.68	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52	$21.01	$14.69	$21.40
Jun		$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20	$15.56	$22.35
Jul		$36.78	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76	$14.66	$21.59
Aug	$35.57		$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57	$14.58	$20.52
Sep	$34.07		$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19	$15.16	$23.06
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35	$29.20
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47	$32.85
Average	$36.32	$37.51	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.54	$21.64	$16.87	$23.03

Table 6-28 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In 2021, the highest zonal LMP in PJM was higher than the NBT threshold price 8,218 hours out of 8,760 hours, or 93.8 percent of all hours. Reductions occurred in 3,032 hours, 36.9 percent, of those 8,218 hours in 2021. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2020, through December 31, 2021. There are no economic

74 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 117 (Nov. 1, 2021).

payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reported reductions occurred in none of the hours in which LMP was below the NBT threshold price in 2021, and 0.1 percent (1 hour) of the hours in which LMP was below the NBT threshold price in 2020.

Table 6-28 Hours with price higher than NBT and economic load response occurrences in those hours: 2020 through 2021

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	2020	2021	2020	2021	Percent Change	2020	2021	Percentage Change
Jan	744	744	569	741	30.2%	38.1%	11.9%	(26.3%)
Feb	696	672	513	667	30.0%	15.0%	50.2%	35.2%
Mar	743	743	558	698	25.1%	9.0%	12.5%	3.5%
Apr	720	720	606	618	2.0%	2.0%	21.4%	19.4%
May	744	744	635	636	0.2%	19.5%	24.4%	4.8%
Jun	720	720	495	592	19.6%	36.4%	44.9%	8.6%
Jul	744	744	675	727	7.7%	50.1%	49.1%	(1.0%)
Aug	744	744	695	744	7.1%	24.9%	54.7%	29.8%
Sep	720	720	648	720	11.1%	7.4%	43.2%	35.8%
Oct	744	744	676	744	10.1%	3.3%	48.5%	45.3%
Nov	721	721	607	721	18.8%	14.2%	52.6%	38.4%
Dec	744	744	712	610	(14.3%)	18.7%	25.2%	6.6%
Total	8,784	8,760	7,389	8,218	11.2%	19.8%	36.9%	17.1%

Energy Efficiency

Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for other capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator. EE resources do not produce power, but reduce power consumption. The Nominated MW for EE resources are not measured, although they could be, but a calculated value based on a set of largely unverified and unverifiable assumptions. An installed EE resource may participate as a capacity resource for up to four consecutive delivery years.[75]

Prescriptive energy efficiency MW have an assumed savings calculated based on an assumed installation rate and the difference between the assumed electricity usage of what is being replaced and the assumed electricity usage of the new product. All lighting EE is prescriptive. The majority of EE MW offered into the PJM capacity market is prescriptive energy efficiency MW. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement or verification but instead relies on unverified assumptions and is too imprecise to rely on as a source of capacity comparable to capacity from a power plant. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods.[76] There is no evidence that the programs result in changed behavior or increases in savings.

The MMU recommends that energy efficiency MW not be included in the PJM Capacity Market. The measurement and verification protocols for energy efficiency are too imprecise to rely on as a source of capacity. Effective energy efficiency measures reduce energy usage and capacity usage directly. The reduced market payments are the appropriate compensation.

Energy efficiency resources are included in the PJM Capacity Market. Table 6-29 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2011/2012 through 2022/2023 Delivery Years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[77] Only Kentucky has been authorized by the Commission.[78] The total MW of energy efficiency resources committed increased by 0.1 percent from 4,806.2 MW in the 2021/2022 Delivery Year to 4,810.6 MW in the 2022/2023 Delivery Year.[79]

75 PJM. "Manual 18: PJM Capacity Market," § 4.4, Rev. 51 (Oct. 20, 2021).

76 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 04 (August 22, 2019).

77 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).

78 FERC made an exception for Kentucky when it determined that RERRAs must obtain FERC approval prior to excluding EE. FERC explained that "the Commission accepted such condition at the time the Kentucky Commission approved the integration of Kentucky Power into PJM." 161 FERC ¶ 61,245 at P 66 (2017).

79 See the *2021 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

Table 6-29 Energy efficiency resources (MW): Delivery Years 2011/2012 through 2022/2023

Delivery Year	EE RPM Cleared (UCAP MW)	Total RPM Cleared (UCAP MW)	EE Percent Cleared
2011/2012	76.4	134,139.6	0.1%
2012/2013	666.1	141,061.8	0.5%
2013/2014	904.2	159,830.5	0.6%
2014/2015	1,077.7	161,092.4	0.7%
2015/2016	1,189.6	173,487.4	0.7%
2016/2017	1,723.2	179,749.0	1.0%
2017/2018	1,922.3	180,590.3	1.1%
2018/2019	2,296.3	175,957.4	1.3%
2019/2020	2,528.5	177,040.6	1.4%
2020/2021	3,569.5	173,688.5	2.1%
2021/2022	4,806.2	174,713.0	2.8%
2022/2023	4,810.6	144,477.3	3.3%

Distributed Energy Resources

Distributed Energy Resources (DER) are not well defined, but generally include small scale generation directly connected to the grid, generation connected to distribution level facilities and behind the meter generation.[80] For example, Table 6-10 shows the fuel mix of behind the meter generation participating as emergency demand response in the 2019/2020 Delivery Year. Clear rules for defining DERs and for defining the ways in which DERs will interact with the wholesale power markets do not yet exist, although the development of those rules is under active discussion.[81] [82] DERs should be treated like other resources. Creating preferential treatment for DERs could create an incentive to move resources behind the meter in a manner inconsistent with efficiency and competitive markets. FERC directed that DER aggregation be as geographically broad as technically feasible.[83]

The current demand response rules appropriately restrict demand response from injecting power into the grid and receiving demand response revenue. At the January 30, 2019, Demand Response Subcommittee meeting, PJM, without a stakeholder process or FERC approval, decided to allow some economic load response payments when economic load response resources injects power into the grid. PJM's test compares the total benefits of running the generator which includes generation payments and assumed retail rate savings against the total cost of the generator. If the total cost of the generator is greater than the benefits, then the resource would receive economic load response payments while injecting. The use of a retail rate in calculating wholesale power market benefits raises significant issues analogous to net metering that require discussion and tariff changes. PJM should not include retail rate benefits in the definition of demand response without approval of FERC.

Aggregation to a single node is technically feasible. Allowing DER aggregation across nodes is not necessary and is not consistent with the nodal market design. Getting the rules correct at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undercuts the efficiency and competitiveness of the power markets.

FERC issued Order No. 2222 on September 17, 2020, requiring RTOs and ISOs to revise their tariffs to accommodate participation of distributed energy resources (DERs) in the wholesale market.[84] FERC Order No. 2222 defined DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter" and included demand response resources in the definition. The goal of FERC Order No. 2222 is to remove barriers for small distributed resources to enter the wholesale market by allowing them to aggregate and relaxing some qualification and performance requirements. The order states that removing barriers would encourage competition which can increase the efficiency of the RTO markets and reduce the risk of over procurement by including DERs in RTOs' planning.[85] PJM made a compliance filing at FERC on February 1, 2022.

Getting the rules correct at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undercuts the efficiency and competitiveness of the power markets. The fact that DERs' impact on the transmission system is currently negligible should not be an excuse to create inefficient rules. An increase in DERs will change flows

80 Some energy storage facilities may be DERs. FERC Order No. 841 requires that energy storage resources have access to capacity, energy and ancillary service markets. *See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 at P 1 (2018).

81 In PJM, the Distributed Energy Resources Subcommittee (DERSC) is currently discussing these issues. *Distributed Energy Resources Subcommittee*, PJM, <http://www.pjm.com/committees-and-groups/subcommittees/ders.aspx>.

82 See "Notice of Technical Conference," Docket No. RM18-9-000 and AD18-10-000 (February 15, 2018); "Technical Conference Distributed Energy Resources," Docket No. RM18-9-000 and AD18-10-000 (April 10, 2018).

83 162 FERC ¶ 32,718 at P 139 (2016).

84 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020).

85 Id. PP 6-7.

on the power grid. No rules, jurisdictional issues or the lack of a transmission interconnection process should prevent PJM from acquiring all necessary information to protect the reliability and the efficiency of the wholesale power markets.

The new DER market rules should not threaten the nodal market principle or the reliability of the transmission system. Allowing DER aggregation across nodes is not necessary and would distort market signals indicating where capacity and energy are needed. PJM proposed a single node aggregation, which is consistent with nodal market design. But the accuracy of the selection of the primary node, especially in real time, is not guaranteed. PJM's proposal does not include regular updates to the primary node information that is provided during the registration process. PJM should have accurate information about a resource's location and to have the ability to update the information as needed for system reliability and correct nodal pricing.

The EDCs' dual role as the distribution system operator and as a DER aggregator is a threat to PJM's competitive market. When an EDC, acting in its proposed role as a market participant, controls its competitors' access to the market, the result is structurally not competitive. The result would be to create barriers to competition, exactly the opposite of FERC's intent. The proposed design would give EDCs market power. EDCs can also control competitors' access to sensitive market data including meter data. For example, EDCs have an inherent advantage over their competitors due to their knowledge of the best potential locations on their distribution system for DERs. EDCs already have metering equipment in place for retail use while competitors will need to install new equipment. EDCs can recover the cost of deploying any necessary metering devices through cost of service ratemaking, which guarantees return on investment, while competitors face market risks. This dual role would give EDCs market power. The result will be uncompetitive wholesale market rates. The role of the EDCs as it affects the wholesale power market is within FERC's authority to ensure just and reasonable wholesale rates. The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role.

The same standards should apply to DER Aggregation Resources as apply to all other resources in the PJM markets. Under the proposed DER rules, favorable treatment of resources that participate in the DER aggregation model over other market participants includes: exemption from the PJM interconnection process; no must offer requirement in the capacity market; exemption from the RPM Minimum Offer Price Rule (MOPR); exemption from the market seller offer cap when co-located with retail load; and ability to reduce load and inject power into the grid at the same time. These exemptions from basic market rules are not appropriate even for small participants and are not necessary to facilitate participation. But large DERs that are already capable of participating in the PJM markets under the current rules should not be given the option to exploit the new rules for DER Aggregation Resources to avoid the obligations of market participation. PJM proposed the maximum size requirement of 5 MW for component DERs but did not propose a maximum size requirement for DER Aggregation Resources.[86] This loophole would allow large DERs to divide one large resource into multiple DERs less than 5 MW and register them as one DER Aggregation Resource. The goal of FERC Order No. 2222 is to remove barriers for small distributed resources. To avoid this loophole, there should be a maximum size requirement on the DER Aggregation Resource. The MMU recommends that PJM include a 5 MW maximum size cap on DER aggregations.

Energy injections from resources that also reduce load should be treated the same as any energy injection from other resource types. PJM has not proposed tariff language changes regarding demand response resources with energy injection capability. Rules for demand response resources and rules for generation resources are different and often conflicting. Resources that can both curtail load and inject energy require a distinct set of rules to ensure that they are not compensated for capacity and energy beyond their actual capability. For example, the tariff should clearly define how the customer baseline ("CBL") is calculated for demand response resources with injection capability.

86 Individual DERs in DER Aggregation Resources. See definitions in the PJM compliance filing.

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear, solar, and wind generating units.

Overview

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and gas prices were significantly higher in 2021 than in 2020.
- In 2021, average energy market net revenues increased by 76 percent for a new combustion turbine (CT), 78 percent for a new combined cycle (CC), 642 percent for a new coal plant (CP), 86 percent for a new nuclear plant, 129 percent for a new diesel (DS), 67 percent for a new onshore wind installation, 83 percent for a new offshore wind installation and 77 percent for a new solar installation compared to 2020.
- The price of natural gas increased by significantly more than the price of coal in 2021. As a result, the marginal costs of a new CC and a new CT were greater than the marginal cost of a new CP in February 2021 and the marginal costs of a new CT were greater than the marginal cost of a new CP from July through November 2021 as a result of higher gas prices.
- Based on Western Hub prices, the spark spread in 2021 increased by 63 percent, the spark spread standard deviation increased by 104 percent, the dark spread increased by 208 percent, and the dark spread standard deviation increased by 112 percent.
- In 2021, capacity market revenue accounted for 52 percent of total net revenues for a new CT, 38 percent for a new CC, 83 percent for a new CP, 14 percent for a new nuclear plant, 85 percent for a new DS, 7 percent for a new onshore wind installation, 11 percent for a new offshore wind installation and 8 percent for a new solar installation.
- In 2021, a new CC would have received sufficient net revenue to cover levelized total costs in 14 zones. No new CT, CP, nuclear, or DS units would have received sufficient net revenue to cover levelized total costs in any zone.
- In 2021, a new entrant onshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. Net revenues would have covered between 45 and 51 percent of levelized total costs of a new entrant onshore wind installation in AEP, APS, COMED and PE. Renewable energy credits accounted for at least 28 percent of the total net revenue of an onshore wind installation.
- In 2021, a new entrant offshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the three zones analyzed. Net revenues would have covered between 28 and 32 percent of levelized total costs. Renewable energy credits accounted for 26 percent of the total net revenue of an offshore wind installation.
- In 2021, a new entrant solar installation would have covered more than 100 percent of levelized total costs in all five of the five zones analyzed. Renewable energy credits accounted for at least 59 percent of the total net revenue of a solar installation.
- In 2021, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2021, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units.
- All existing PJM nuclear plants more than covered their avoidable costs from energy and capacity market revenues in 2021 and are expected to more than cover their avoidable costs from energy and capacity market revenues in 2022.
- Using a forward analysis, a total of 2,230 MW of CT, diesel, and oil fired capacity are at risk of retirement, in addition to the units that are currently planning to retire or are expected to retire as a result of state and federal environmental regulations.

Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

Net Revenue

When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets and from the provision of black start and reactive services and capability, less the short run marginal costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue. Net revenue is the contribution to fixed costs, which include a return on investment, depreciation and income taxes, and to avoidable costs, which include long term and intermediate term operation and maintenance expenses.[1] Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

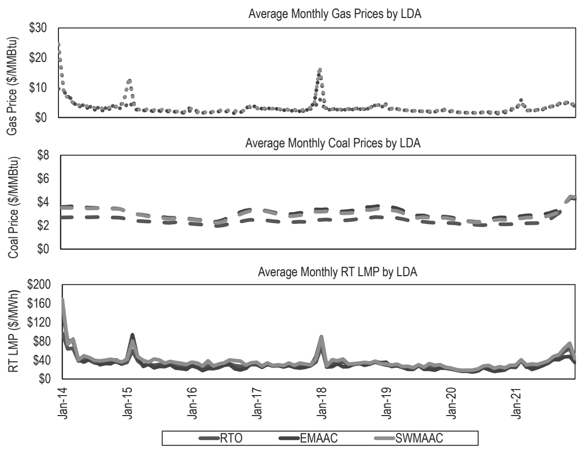
In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity and to encourage maintaining existing capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. PJM real-time energy market prices increased significantly in 2021. The load-weighted, average, real-time LMP was 82.8 percent higher in 2021 than in 2020, $39.78 per MWh versus $21.77 per MWh. Gas prices and coal prices increased in 2021 compared to 2020. Gas price volatility increased and gas price differences among regions increased. The price of eastern natural gas was 106.2 percent higher and the price of western natural gas was 143.3 percent higher; the price of Northern Appalachian coal was 42.3

1 Avoidable costs are sometimes referred to as going forward costs.

percent higher; the price of Central Appalachian coal was 51.9 percent higher; and the price of Powder River Basin coal was 38.0 percent higher (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through 2021



Spark Spreads and Dark Spreads

The spark or dark spread is defined as the difference between the LMP received for selling power and the cost of fuel used to generate power, converted to a cost per MWh. The spark spread compares power prices to the cost of gas and the dark spread compares power prices to the cost of coal. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

Spark spreads increased in 2021 compared to 2020 with the exception of COMED, and the volatility of spark spreads increased. Dark spreads increased significantly in 2021 compared to the very low levels in 2020.

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviations.

Table 7-1 Peak hour spark and dark spreads ($/MWh)

	BGE		COMED		PSEG		Western Hub	
	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2020	$16.70	$9.55	$9.48	$2.94	$9.33	$0.15	$13.10	$5.65
2021	$27.85	$24.14	$8.68	$15.19	$13.76	$7.92	$21.32	$17.41

Table 7-2 Peak hour spark and dark spread standard deviation ($/MWh)

	BGE		COMED		PSEG		Western Hub	
	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2020	$23.3	$23.4	$13.5	$14.0	$12.2	$12.7	$15.5	$15.5
2021	$41.1	$41.8	$77.0	$30.3	$23.1	$25.1	$31.7	$32.8

Figure 7-2 shows the hourly spark spread for peak hours for BGE, COMED, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2020 through 2021[2]

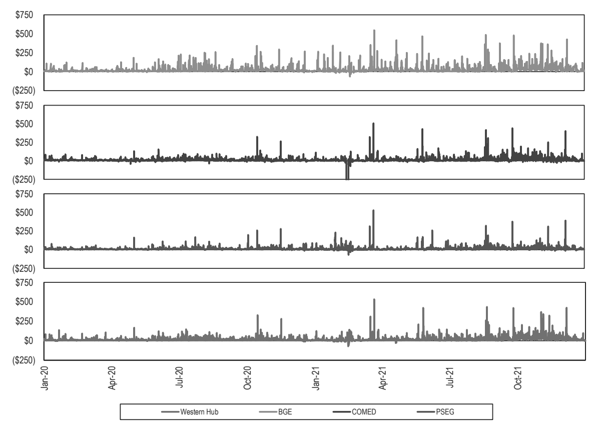
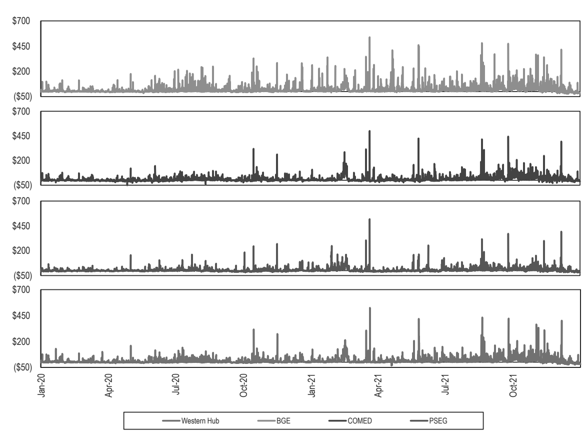


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2020 through 2021[3]



2 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for COMED, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

3 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, daily coal prices, and average transportation costs by coal type; Powder River Basin coal for COMED, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets.

Analysis of energy market net revenues for a new entrant includes eight power plant configurations:

- The CT plant is a single GE Frame 7HA.02 CT with an installed capacity of 360.1 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant includes two GE Frame 7HA.02 CT and a single steam turbine generator with an installed capacity of 1,137.2 MW, equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT, with steam reheat, and SCR for NO_x reduction.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 104 Siemens 2.9 MW wind turbines located in COMED with an installed capacity of 301.6 MW.
- The offshore wind installation includes of 43 Siemens 7.0 MW wind turbines with an installed capacity of 301.0 MW.
- The solar installation is a 236 acre ground mounted fixed tilt solar farm located in DOM with an installed AC capacity of 100 MW.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4] [5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.[6] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[8] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day annual planned outage in the fall season.

Revenues for the provision of reactive services include both real-time reactive service revenues and reactive capability revenues. Reactive service revenues for CTs are based on the average reactive service revenue per MW-year received by all CTs with 20 or fewer operating years. Reactive service revenues for CC, CP, and DS units are based on the average reactive service revenue per MW-year received by all generators of that unit type. Table 7-3 includes the class average reactive service revenues received plus reactive capability revenue by unit type.[9]

Table 7-3 New entrant reactive revenue (Dollars per MW-year)

	Reactive				
	CT	CC	CP	Diesel	Nuclear
2014	$3,721	$4,046	$3,574	$3,350	$3,350
2015	$3,673	$4,911	$3,386	$3,350	$3,350
2016	$3,436	$4,573	$3,470	$3,350	$3,350
2017	$3,885	$3,591	$3,438	$3,350	$3,350
2018	$4,150	$3,350	$4,929	$3,350	$3,350
2019	$3,519	$3,350	$3,629	$3,350	$3,350
2020	$4,045	$3,495	$3,513	$3,358	$3,350
2021	$3,734	$2,648	$1,366	$6,366	$1,640

4 Hourly ambient conditions supplied by DTN.
5 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
6 CO_2 emission allowance costs only included for states participating in RGGI, including New Jersey.
7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 Reactive capability revenue by unit type is located in the *2021 State of the Market Report for PJM*, Volume 2; Section 10, Ancillary Services Markets

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[10] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[11] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt month prices, adjusted for rail transportation costs.[12] Net revenues are calculated for all zones except OVEC.[13]

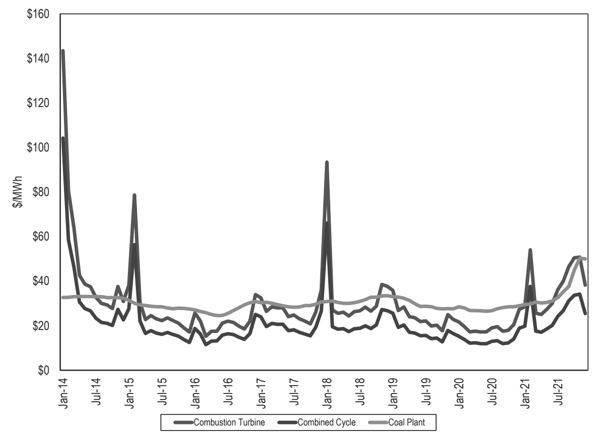
Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[14] [15] Average short run marginal costs are shown, including all components, in Table 7-4 and the short run marginal component of VOM is also shown separately.

Table 7-4 Average short run marginal costs: 2021

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$37.73	9,241	$0.36
CC	$25.51	6,296	$1.41
CP	$36.02	9,250	$4.21
DS	$171.08	9,660	$0.25
Nuclear	$0.00	NA	$0.00
Wind	$0.00	NA	$0.00
Wind (off shore)	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014 shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-4). The marginal costs of a new CC and a new CT were greater than the marginal cost of a new CP in February 2021 and the marginal costs of a new CT were greater than the marginal cost of a new CP from July through November 2021 as a result of higher gas prices.

Figure 7-4 Average short run marginal costs: 2014 through 2021



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

Gas prices, coal prices, and energy prices are reflected in new entrant capacity factors. The new entrant coal plant ran for significantly more hours in 2021 than in 2020, returning to levels consistent with years prior to 2020. Table 7-5 shows the average capacity factor by a new entrant unit.

Table 7-5 Average capacity factor: 2014 through 2021

	CT	CC	CP	DS	Nuclear	On Shore Wind	Solar
2014	48%	73%	58%	1%	92%	25%	15%
2015	64%	74%	50%	1%	92%	25%	17%
2016	65%	75%	44%	0%	92%	22%	16%
2017	53%	70%	38%	0%	94%	26%	17%
2018	52%	79%	41%	1%	94%	27%	16%
2019	52%	77%	24%	0%	93%	26%	15%
2020	48%	76%	13%	0%	93%	26%	16%
2021	42%	76%	37%	1%	93%	24%	17%

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the energy and ancillary service markets. In the PJM market design, the sale of capacity provides an important source of revenues that contribute to covering generator avoidable costs and fixed costs. Capacity revenue for 2021 includes five

10 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
11 Gas daily cash prices obtained from Platts.
12 Coal prompt month prices obtained from Platts.
13 The Ohio Valley Electric Corporation (OVEC) includes a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, but does not occupy a single geographic footprint like the other control zones.
14 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
15 VOM rates provided by Pasteris Energy, Inc.

months of the 2020/2021 RPM capacity market clearing price and seven months of the 2021/2022 RPM capacity market clearing price.[16]

Table 7-6 Capacity revenue by zone (Dollars per MW-year): 2014 through 2021[17]

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	$66,206	$56,448	$50,948	$43,669	$65,655	$58,103	$57,650	$63,835
AEP	$31,149	$48,128	$33,377	$34,645	$53,235	$45,873	$31,371	$41,525
APS	$31,149	$48,128	$33,377	$34,645	$53,216	$45,948	$31,425	$41,647
ATSI	$31,149	$95,422	$78,709	$42,929	$53,124	$45,781	$31,351	$48,221
BGE	$63,360	$56,448	$50,948	$43,669	$52,953	$45,651	$33,380	$49,311
COMED	$31,149	$48,128	$33,377	$34,645	$63,994	$75,508	$70,901	$70,256
DAY	$31,149	$48,128	$33,377	$34,645	$52,760	$44,969	$30,957	$41,516
DOM	$31,149	$48,128	$33,377	$34,645	$53,219	$45,665	$31,221	$41,516
DPL	$66,206	$56,448	$50,948	$43,669	$65,106	$57,607	$57,573	$63,835
DUKE	$31,149	$48,128	$33,377	$34,645	$52,338	$44,515	$42,289	$49,590
DUQ	$31,149	$48,128	$33,377	$34,645	$53,045	$45,567	$31,239	$41,516
EKPC	$31,149	$48,128	$33,377	$34,645	$52,400	$44,611	$30,883	$41,516
JCPLC	$66,206	$56,448	$50,948	$43,669	$64,763	$56,462	$56,932	$63,832
MEC	$63,360	$56,448	$50,948	$43,669	$53,353	$46,138	$33,526	$42,952
PE	$63,360	$56,448	$50,945	$43,667	$53,154	$45,760	$33,376	$42,966
PECO	$66,206	$56,448	$50,948	$43,669	$65,707	$58,548	$57,940	$63,835
PEPCO	$66,529	$56,448	$50,948	$43,669	$53,323	$46,207	$33,590	$42,952
PPL	$63,360	$56,448	$50,948	$43,669	$52,218	$45,398	$33,569	$42,980
PSEG	$72,567	$60,936	$67,224	$73,401	$79,190	$59,582	$58,370	$69,285
REC	$72,567	$60,936	$67,224	$73,401	$79,190	$59,582	$58,370	$69,285
PJM	$46,247	$54,646	$48,568	$44,809	$58,432	$52,008	$42,199	$50,692

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-7 includes new entrant levelized total costs for selected technologies.

Net revenues include net revenues from the PJM Energy Market, from the PJM Capacity Market and from any applicable ancillary services plus RECs for wind installations and SRECs for solar installations.

Levelized Total Costs

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[18 19 20]

	20-Year Levelized Total Cost							
	2014	2015	2016	2017	2018	2019	2020	2021
Combustion Turbine	$122,604	$120,675	$119,346	$114,557	$118,116	$121,612	$120,720	$134,297
Combined Cycle	$146,443	$146,300	$148,327	$129,731	$113,641	$116,781	$119,180	$132,378
Coal Plant	$504,050	$517,017	$523,540	$528,701	$562,747	$581,567	$599,912	$635,027
Diesel Plant	$161,746	$170,500	$173,182	$158,817	$154,683	$169,859	$177,843	$206,097
Nuclear Plant	$880,770	$935,659	$963,107	$1,349,850	$1,178,607	$1,383,428	$1,383,428	$1,706,638
On Shore Wind Installation (with 1603 grant)	$198,033	$202,874	$231,310	$188,747	$214,780	$214,618	$208,167	$245,031
Off Shore Wind Installation (with 1603 grant)	-	-	-	-	$683,771	$710,472	$707,739	$783,374
Solar Installation (with 1603 grant)	$236,289	$234,151	$218,937	$200,931	$232,230	$243,936	$189,391	$153,261
Battery Storage	-	-	-	-	-	$99,232	-	$86,569

16 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant base residual auctions. Differences in capacity market revenues reflect differences in clearing prices across LDAs.
17 See the *2021 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.
18 Levelized total costs provided by Pasteris Energy, Inc.
19 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009, the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the solar and wind technologies.
20 The battery is a 25 MWh battery capable of producing 25 MW for 1 hour or 2.5 MW for 10 hours. The 20-year levelized total cost for the battery is presented in $/MWh.

Levelized Cost of Energy

The levelized cost of energy is a measure of the total cost per MWh of energy from a technology, including all fixed and variable costs. If a unit's revenues cover its levelized cost of energy, it is covering all its costs and earning the target rate of return. The levelized cost of all units is sensitive to the capacity factor used.

Table 7-8 shows the levelized cost of energy for a new entrant unit by technology type operating at the capacity factor for the new entrant unit type. CCs had a low levelized cost of energy in 2021 because they had a high capacity factor, which increases the MWh over which costs are spread. DS units had a high levelized cost of energy because DS units had a very low capacity factor, which decreases the MWh over which costs are spread. The levelized costs of onshore wind, offshore wind and solar are higher than for a CT or CC and lower than for a CP.

The levelized cost of all units is sensitive to the capacity factor used. The LCOE of a solar installation is shown using a capacity factor of 17 percent. The LCOE of a solar installation is $51/MWh if a capacity factor of 34 percent is used because the costs are distributed over a greater number of MWh.

Table 7-8 Levelized cost of energy: 2021

	CT	CC	CP	DS	Nuclear	Wind (On Shore)	Wind (Off Shore)	Solar
Levelized cost ($/MW-year)	$134,297	$132,378	$635,027	$206,097	$1,706,638	$245,031	$783,374	$153,261
Short run marginal costs ($/MWh)	$37.73	$25.51	$36.02	$171.08	$0.00	$0.00	$0.00	$0.00
Capacity factor (%)	42%	76%	37%	1%	92%	24%	45%	17%
Levelized cost of energy ($/MWh)	$74	$45	$232	$4,144	$212	$116	$199	$104

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least two hours, or any profitable hours bordering the profitable day-ahead or real-time block.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The economically dispatched new entrant CT ran for more than twice as many hours as large CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were higher in all zones in 2021 as a result of significantly higher and more variable energy prices (Table 7-9).

Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch: 2014 through 2021 (Dollars per installed MW-year)[21]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$84,836	$50,794	$52,699	$28,997	$34,625	$24,051	$9,052	$13,214	46%
AEP	$74,978	$69,424	$55,360	$36,440	$72,928	$44,651	$33,410	$57,279	71%
APS	$101,376	$97,467	$61,544	$48,564	$71,758	$24,930	$19,200	$38,134	99%
ATSI	$55,573	$59,263	$53,052	$38,949	$86,415	$45,733	$33,690	$56,512	68%
BGE	$99,953	$79,092	$92,965	$40,064	$52,362	$33,157	$31,522	$55,829	77%
COMED	$34,672	$32,378	$34,109	$22,162	$32,571	$23,501	$18,530	$32,811	77%
DAY	$49,905	$57,180	$51,652	$37,682	$81,172	$51,092	$40,100	$72,267	80%
DOM	$67,601	$68,742	$64,140	$37,075	$57,676	$35,826	$28,998	$62,761	116%
DPL	$65,984	$33,315	$26,615	$19,853	$28,229	$14,604	$14,297	$30,640	114%
DUKE	$44,998	$54,542	$48,954	$36,051	$88,626	$46,495	$36,049	$67,055	86%
DUQ	$52,029	$81,445	$72,284	$46,308	$57,854	$30,516	$31,432	$48,663	55%
EKPC	$65,277	$56,514	$48,036	$30,024	$55,351	$37,022	$29,760	$55,345	86%
JCPLC	$85,599	$48,957	$48,143	$32,391	$32,118	$23,755	$9,133	$12,844	41%
MEC	$87,153	$87,946	$71,178	$55,484	$44,929	$29,492	$36,074	$61,924	72%
PE	$139,617	$140,467	$89,309	$63,620	$83,911	$41,273	$44,218	$65,558	48%
PECO	$89,208	$86,138	$66,527	$46,494	$38,961	$22,037	$26,723	$27,052	1%
PEPCO	$70,396	$50,496	$46,753	$25,829	$42,134	$21,041	$14,094	$37,521	166%
PPL	$212,119	$155,947	$72,532	$59,248	$81,558	$28,443	$30,634	$53,261	74%
PSEG	$108,432	$99,278	$71,988	$54,477	$44,574	$24,808	$9,575	$16,699	74%
REC	$80,365	$55,796	$53,746	$34,467	$35,019	$25,217	$11,413	$26,286	130%
PJM	$58,381	$73,259	$59,079	$39,709	$56,138	$31,382	$25,395	$44,583	76%

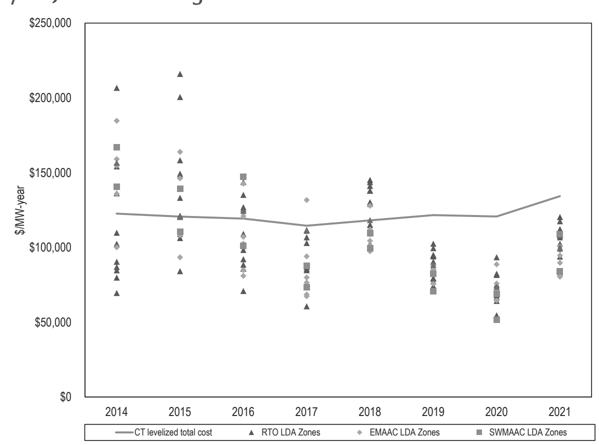
In 2021, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-10).

Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue: 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	126%	92%	90%	67%	88%	70%	59%	60%
AEP	90%	100%	77%	65%	110%	77%	57%	76%
APS	111%	124%	82%	76%	109%	61%	45%	62%
ATSI	74%	131%	113%	75%	122%	78%	57%	81%
BGE	136%	115%	123%	76%	93%	68%	57%	81%
COMED	57%	70%	59%	53%	85%	84%	77%	80%
DAY	69%	90%	74%	67%	117%	82%	62%	88%
DOM	84%	100%	85%	66%	97%	70%	53%	80%
DPL	111%	77%	68%	59%	83%	62%	63%	73%
DUKE	65%	88%	72%	65%	123%	78%	68%	90%
DUQ	71%	110%	91%	74%	97%	65%	55%	70%
EKPC	82%	90%	71%	60%	95%	70%	54%	75%
JCPLC	127%	90%	86%	70%	86%	69%	58%	60%
MEC	126%	123%	105%	90%	87%	65%	61%	81%
PE	169%	166%	120%	97%	120%	74%	68%	84%
PECO	130%	121%	101%	82%	92%	69%	73%	70%
PEPCO	115%	92%	85%	64%	84%	58%	43%	63%
PPL	228%	179%	106%	93%	117%	64%	57%	74%
PSEG	151%	136%	120%	115%	108%	72%	60%	67%
REC	128%	100%	104%	98%	100%	73%	61%	74%
PJM	88%	109%	93%	77%	101%	71%	59%	74%

Figure 7-5 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

Figure 7-5 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2021



21 The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.[22] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were higher in all zones as a result of significantly higher energy prices, despite higher gas costs (Table 7-11).

Table 7-11 Energy net revenue for a new entrant CC under economic dispatch: 2014 through 2021 (Dollars per installed MW-year)[23]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$126,626	$74,716	$68,004	$50,259	$67,427	$51,397	$29,870	$42,582	43%
AEP	$109,036	$96,826	$76,488	$59,550	$109,104	$74,927	$55,042	$96,601	76%
APS	$154,231	$140,352	$98,353	$76,282	$117,114	$64,383	$54,111	$94,052	74%
ATSI	$82,670	$87,902	$74,459	$60,987	$120,740	$75,846	$55,328	$97,104	76%
BGE	$155,871	$125,088	$129,148	$71,490	$98,258	$74,567	$67,515	$115,493	71%
COMED	$47,229	$54,134	$53,187	$38,278	$56,006	$45,150	$34,101	$60,244	77%
DAY	$76,213	$86,691	$73,887	$61,188	$117,206	$81,573	$62,751	$114,111	82%
DOM	$106,993	$98,562	$86,903	$60,969	$92,066	$67,760	$50,597	$103,129	104%
DPL	$109,317	$50,497	$43,345	$27,674	$47,707	$21,528	$17,501	$46,552	166%
DUKE	$66,685	$82,518	$70,201	$57,922	$122,183	$76,621	$57,948	$107,384	85%
DUQ	$82,827	$95,948	$86,877	$64,871	$91,162	$57,652	$52,762	$87,864	67%
EKPC	$94,596	$84,530	$68,479	$52,705	$91,178	$67,152	$51,066	$94,868	86%
JCPLC	$129,943	$73,929	$63,904	$53,388	$64,877	$51,790	$30,243	$45,452	50%
MEC	$125,883	$104,606	$82,491	$71,970	$78,513	$57,663	$53,852	$100,142	86%
PE	$177,418	$147,403	$99,614	$78,602	$118,315	$70,370	$62,647	$106,350	70%
PECO	$130,722	$105,080	$77,959	$64,772	$74,100	$48,733	$44,819	$62,746	40%
PEPCO	$116,024	$96,499	$85,838	$54,535	$84,100	$58,426	$39,143	$83,010	112%
PPL	$232,421	$155,117	$83,707	$73,720	$108,706	$54,358	$48,885	$91,085	86%
PSEG	$157,086	$118,918	$83,897	$72,328	$81,207	$53,768	$32,989	$50,230	52%
REC	$125,098	$79,151	$68,279	$55,405	$66,816	$53,845	$33,766	$60,666	80%
PJM	$100,026	$97,923	$78,751	$60,345	$90,339	$60,375	$46,747	$82,983	78%

22 All starts associated with combined cycle units are assumed to be warm starts.
23 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

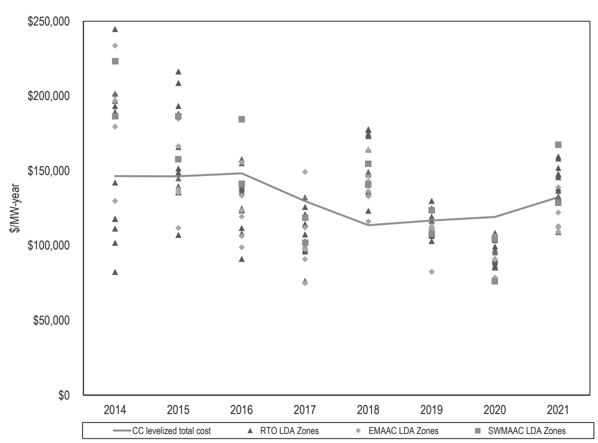
In 2021, a new CC would have received sufficient net revenue to cover levelized total costs in 14 zones (Table 7-12).

Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue: 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	134%	93%	83%	75%	120%	97%	76%	82%
AEP	98%	102%	77%	75%	146%	106%	75%	106%
APS	129%	132%	92%	88%	153%	97%	75%	105%
ATSI	80%	129%	106%	83%	156%	107%	76%	112%
BGE	152%	127%	125%	92%	136%	106%	88%	126%
COMED	56%	73%	61%	59%	109%	106%	91%	101%
DAY	76%	96%	75%	77%	153%	111%	82%	120%
DOM	97%	104%	84%	76%	131%	100%	72%	111%
DPL	123%	76%	67%	58%	102%	71%	66%	85%
DUKE	70%	93%	73%	74%	157%	107%	87%	121%
DUQ	81%	102%	84%	79%	130%	91%	73%	100%
EKPC	89%	94%	72%	70%	129%	99%	72%	105%
JCPLC	137%	92%	81%	78%	117%	96%	76%	85%
MEC	132%	113%	93%	92%	119%	92%	76%	110%
PE	167%	143%	105%	97%	154%	102%	84%	115%
PECO	137%	114%	90%	86%	126%	95%	89%	98%
PEPCO	127%	108%	95%	78%	124%	92%	64%	97%
PPL	205%	148%	94%	93%	145%	88%	72%	103%
PSEG	160%	126%	105%	115%	144%	100%	80%	92%
REC	138%	99%	94%	102%	131%	100%	80%	100%
PJM	103%	108%	89%	84%	134%	99%	78%	103%

Figure 7-6 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

Figure 7-6 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2021



New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CP plant energy market net revenues were higher in all zones as a result of significantly higher energy prices, despite higher coal prices (Table 7-13).

Table 7-13 Energy net revenue for a new entrant CP: 2014 through 2021 (Dollars per installed MW-year)[24]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$115,697	$48,138	$10,643	$7,601	$31,260	$4,279	$1,176	$6,008	411%
AEP	$113,144	$51,079	$38,517	$35,658	$63,698	$19,004	$7,807	$53,319	583%
APS	$105,457	$42,147	$14,995	$17,879	$43,519	$5,688	$2,413	$19,025	688%
ATSI	$124,565	$51,785	$34,262	$35,618	$66,002	$14,847	$4,630	$47,849	934%
BGE	$167,855	$84,957	$46,952	$18,903	$51,185	$9,970	$6,209	$31,297	404%
COMED	$112,699	$39,698	$28,732	$26,632	$37,054	$12,822	$2,983	$53,710	1,701%
DAY	$117,447	$50,088	$31,524	$34,467	$62,462	$18,807	$9,763	$60,484	520%
DOM	$156,315	$90,406	$44,653	$27,496	$64,695	$17,805	$9,438	$58,809	523%
DPL	$167,509	$71,672	$21,952	$16,869	$50,348	$10,285	$6,805	$22,329	228%
DUKE	$106,048	$46,117	$28,460	$31,389	$67,260	$16,583	$8,587	$54,856	539%
DUQ	$98,952	$40,461	$29,819	$32,250	$65,589	$13,181	$5,229	$45,942	779%
EKPC	$102,305	$38,208	$24,436	$25,144	$43,091	$12,475	$6,577	$49,103	647%
JCPLC	$119,656	$46,725	$7,933	$8,452	$30,416	$4,074	$1,386	$6,107	341%
MEC	$153,809	$64,861	$19,709	$20,908	$49,202	$9,800	$6,897	$41,405	500%
PE	$129,578	$59,867	$23,206	$16,790	$46,051	$9,533	$5,186	$36,910	612%
PECO	$111,207	$44,763	$8,709	$7,691	$29,007	$4,053	$871	$14,715	1,590%
PEPCO	$114,167	$41,146	$10,499	$6,142	$29,304	$4,342	$1,347	$24,629	1,728%
PPL	$110,250	$43,645	$7,050	$7,770	$28,732	$3,234	$1,069	$24,886	2,227%
PSEG	$174,390	$72,812	$13,651	$12,882	$35,986	$6,201	$489	$6,048	1,137%
REC	$170,401	$73,077	$13,238	$12,236	$35,919	$7,234	$1,279	$11,829	825%
PJM	$128,573	$55,083	$22,947	$20,139	$46,539	$10,211	$4,507	$33,463	642%

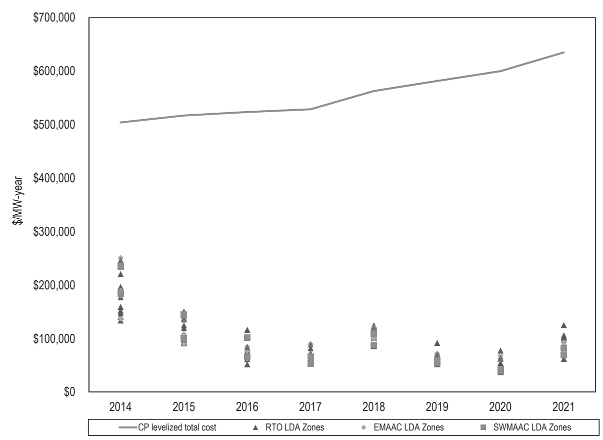
In 2021, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). This has been the consistent result for a new CP for the entire period of the analysis.

Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue: 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	37%	21%	12%	10%	18%	11%	10%	11%
AEP	29%	20%	14%	14%	22%	12%	7%	15%
APS	28%	18%	10%	11%	18%	10%	6%	10%
ATSI	32%	29%	22%	16%	22%	11%	7%	15%
BGE	47%	28%	19%	12%	19%	10%	7%	13%
COMED	29%	18%	13%	12%	19%	16%	13%	20%
DAY	30%	20%	13%	14%	21%	12%	7%	16%
DOM	38%	27%	16%	12%	22%	12%	7%	16%
DPL	47%	25%	15%	12%	21%	12%	11%	14%
DUKE	28%	19%	12%	13%	22%	11%	9%	17%
DUQ	27%	18%	13%	13%	22%	11%	7%	14%
EKPC	27%	17%	12%	12%	18%	10%	7%	14%
JCPLC	38%	21%	12%	11%	18%	11%	10%	11%
MEC	44%	24%	14%	13%	19%	10%	7%	13%
PE	39%	23%	15%	12%	19%	10%	7%	13%
PECO	36%	20%	12%	10%	18%	11%	10%	13%
PEPCO	37%	20%	12%	10%	16%	9%	6%	11%
PPL	35%	20%	12%	10%	15%	9%	6%	11%
PSEG	50%	27%	16%	17%	21%	12%	10%	12%
REC	49%	27%	16%	17%	21%	12%	11%	13%
PJM	35%	22%	14%	13%	20%	11%	8%	13%

Figure 7-7 shows zonal net revenue and the annual levelized total cost for the new entrant CP by LDA.

Figure 7-7 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2021



New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours and output reflects the class average equivalent availability factor.[25]

24 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

25 The annual class average equivalent availability factor was used in the calculation of energy market net revenues.

New entrant nuclear plant energy market net revenues were higher in all zones as a result of significantly higher energy prices (Table 7-15).

Table 7-15 Energy net revenue for a new entrant nuclear plant: 2014 through 2021 (Dollars per installed MW-year)[26]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$430,088	$273,691	$200,584	$226,845	$285,185	$192,221	$147,168	$260,754	77%
AEP	$358,889	$259,420	$226,969	$241,589	$291,370	$217,407	$170,937	$314,652	84%
APS	$383,546	$282,041	$231,832	$245,633	$302,994	$216,401	$170,914	$316,672	85%
ATSI	$371,823	$262,859	$228,329	$246,859	$305,160	$219,369	$170,965	$312,693	83%
BGE	$482,796	$352,161	$296,138	$268,966	$332,101	$237,019	$194,052	$354,544	83%
COMED	$322,257	$225,655	$213,368	$221,193	$235,676	$191,318	$154,963	$284,104	83%
DAY	$361,855	$261,380	$228,084	$246,977	$301,482	$226,472	$179,830	$332,994	85%
DOM	$430,421	$311,499	$250,271	$260,185	$323,948	$225,667	$176,991	$339,702	92%
DPL	$467,506	$301,832	$224,906	$245,767	$314,185	$203,224	$159,794	$300,139	88%
DUKE	$347,738	$256,348	$223,698	$242,729	$307,041	$220,799	$174,520	$324,772	86%
DUQ	$340,525	$249,258	$222,416	$242,278	$304,190	$216,018	$171,585	$308,427	80%
EKPC	$343,061	$246,594	$218,753	$234,319	$274,749	$214,080	$170,356	$316,730	86%
JCPLC	$434,325	$272,261	$195,704	$231,523	$282,490	$192,909	$147,714	$267,340	81%
MEC	$417,516	$265,313	$198,714	$236,723	$282,769	$199,556	$155,273	$307,271	98%
PE	$394,697	$271,023	$215,556	$236,980	$291,292	$207,398	$162,672	$303,466	87%
PECO	$421,701	$266,837	$193,380	$226,787	$277,512	$188,645	$145,298	$259,904	79%
PEPCO	$467,154	$328,709	$266,428	$263,124	$323,833	$230,232	$180,809	$341,826	89%
PPL	$418,032	$265,864	$195,230	$228,451	$273,036	$188,993	$146,492	$282,094	93%
PSEG	$456,679	$283,287	$200,257	$237,187	$286,834	$194,920	$149,103	$272,398	83%
REC	$451,926	$284,922	$201,343	$237,924	$289,049	$199,553	$153,187	$289,459	89%
PJM	$405,127	$276,048	$221,598	$241,102	$294,245	$209,110	$164,131	$304,497	86%

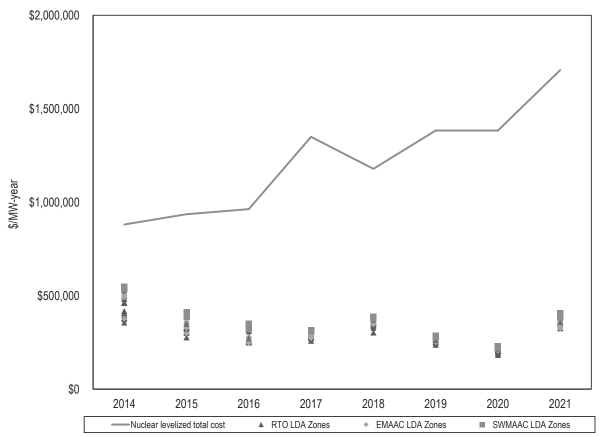
In 2021, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-16). This has been the consistent result for a new nuclear plant for the entire period of the analysis.

Table 7-16 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	57%	36%	26%	20%	30%	18%	15%	19%
AEP	45%	33%	27%	21%	30%	19%	15%	21%
APS	47%	36%	28%	21%	31%	19%	15%	21%
ATSI	46%	39%	32%	22%	31%	19%	15%	21%
BGE	62%	44%	36%	23%	33%	21%	17%	24%
COMED	41%	30%	26%	19%	26%	20%	17%	21%
DAY	45%	33%	27%	21%	30%	20%	15%	22%
DOM	53%	39%	30%	22%	32%	20%	15%	22%
DPL	61%	39%	29%	22%	32%	19%	16%	21%
DUKE	43%	33%	27%	21%	31%	19%	16%	22%
DUQ	43%	32%	27%	21%	31%	19%	15%	21%
EKPC	43%	32%	27%	20%	28%	19%	15%	21%
JCPLC	57%	35%	26%	21%	30%	18%	15%	20%
MEC	55%	35%	26%	21%	29%	18%	14%	21%
PE	52%	35%	28%	21%	30%	19%	14%	20%
PECO	56%	35%	26%	20%	29%	18%	15%	19%
PEPCO	61%	42%	33%	23%	32%	20%	16%	23%
PPL	55%	35%	26%	20%	28%	17%	13%	19%
PSEG	60%	37%	28%	23%	31%	19%	15%	20%
REC	60%	37%	28%	23%	32%	19%	16%	21%
PJM	52%	36%	28%	21%	30%	19%	15%	21%

26 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

Figure 7-8 New entrant nuclear plant net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2021



New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were higher in all zones except DUQ and JCPLC in 2021 as a result of significantly higher and more variable energy prices (Table 7-17).

Table 7-17 Energy market net revenue for a new entrant DS: 2014 through 2021 (Dollars per installed MW-year)

Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$33,114	$13,159	$2,416	$2,554	$10,312	$2,029	$835	$1,512	81%
AEP	$14,469	$3,968	$987	$1,420	$4,154	$5,138	$1,182	$3,654	209%
APS	$18,020	$7,423	$1,051	$1,343	$6,675	$4,662	$2,092	$3,676	76%
ATSI	$14,114	$3,675	$2,090	$1,773	$7,209	$4,537	$2,548	$3,301	30%
BGE	$50,096	$18,305	$8,329	$3,202	$12,785	$6,899	$4,980	$8,366	68%
COMED	$11,320	$2,327	$748	$1,333	$730	$3,476	$821	$3,172	286%
DAY	$14,288	$3,772	$1,044	$1,670	$3,946	$5,570	$1,146	$5,121	347%
DOM	$42,609	$12,064	$2,596	$2,765	$15,094	$5,841	$1,863	$9,114	389%
DPL	$38,453	$19,925	$3,691	$5,637	$14,261	$6,375	$8,788	$16,633	89%
DUKE	$13,467	$3,288	$1,415	$3,069	$6,675	$5,441	$1,013	$4,691	363%
DUQ	$13,132	$3,179	$2,416	$1,517	$9,248	$4,493	$3,973	$3,522	(11%)
EKPC	$14,483	$2,970	$1,054	$972	$1,922	$4,868	$1,003	$4,500	348%
JCPLC	$33,066	$13,042	$923	$2,848	$11,134	$2,085	$1,614	$1,430	(11%)
MEC	$31,992	$13,020	$908	$3,794	$10,974	$2,670	$3,020	$7,291	141%
PE	$15,964	$6,436	$904	$1,699	$5,539	$2,906	$1,355	$3,652	170%
PECO	$32,360	$12,429	$875	$2,839	$9,838	$2,077	$1,421	$1,693	19%
PEPCO	$51,396	$12,842	$3,551	$2,497	$12,363	$6,314	$1,884	$6,302	234%
PPL	$32,931	$13,062	$796	$2,988	$8,799	$1,650	$1,194	$3,052	156%
PSEG	$32,550	$12,650	$1,064	$3,284	$10,325	$2,437	$730	$1,956	168%
REC	$30,724	$13,740	$1,247	$3,031	$9,703	$2,627	$1,785	$6,473	263%
PJM	$29,787	$9,564	$1,905	$2,512	$8,584	$4,105	$2,162	$4,955	129%

In 2021, the new entrant DS would not have received sufficient net revenue to cover levelized total costs in any zone. This has been the consistent result for a new DS for the entire period of the analysis.

Table 7-18 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue: 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	63%	43%	33%	31%	51%	37%	35%	35%
AEP	30%	33%	22%	25%	39%	32%	20%	25%
APS	32%	35%	22%	25%	41%	32%	21%	25%
ATSI	30%	60%	49%	30%	41%	32%	21%	28%
BGE	72%	46%	36%	32%	45%	33%	23%	31%
COMED	28%	32%	22%	25%	44%	48%	42%	39%
DAY	30%	32%	22%	25%	39%	32%	20%	26%
DOM	48%	37%	23%	26%	46%	32%	20%	28%
DPL	67%	47%	33%	33%	53%	40%	39%	42%
DUKE	30%	32%	22%	26%	40%	31%	26%	29%
DUQ	29%	32%	23%	25%	42%	31%	22%	25%
EKPC	30%	32%	22%	25%	37%	31%	20%	25%
JCPLC	63%	43%	32%	31%	51%	36%	35%	35%
MEC	61%	43%	32%	32%	44%	31%	22%	27%
PE	51%	39%	32%	31%	40%	31%	21%	26%
PECO	63%	42%	32%	31%	51%	38%	35%	35%
PEPCO	75%	43%	33%	31%	45%	33%	22%	27%
PPL	62%	43%	32%	31%	42%	30%	21%	25%
PSEG	67%	45%	41%	50%	60%	38%	35%	38%
REC	66%	46%	41%	50%	60%	39%	36%	40%
PJM	49%	40%	31%	32%	45%	35%	27%	30%

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly assuming the unit generated at the average capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW.[27]

Onshore wind energy market net revenues were higher as a result of significantly higher energy prices.

Table 7-19 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
AEP	$106,499	$78,929	$67,826	$71,312	$93,621	$70,434	$47,589	$78,259	64%
APS	$108,148	$72,504	$62,352	$71,867	$95,329	$58,628	$47,685	$74,369	56%
COMED	$95,745	$67,842	$58,915	$68,278	$65,111	$59,836	$39,899	$74,104	86%
PE	$129,612	$85,543	$65,204	$73,843	$95,776	$55,603	$42,652	$69,386	63%

The new entrant onshore wind installation analysis is based on a 17.6 percent capacity factor (derating factor) for defining the MW offered in the capacity market.[28]

Table 7-20 Capacity market net revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
AEP	$5,482	$8,471	$5,874	$6,097	$9,369	$8,074	$5,521	$7,308
APS	$5,482	$8,471	$5,874	$6,097	$9,366	$8,087	$5,531	$7,330
COMED	$5,482	$8,471	$5,874	$6,097	$11,263	$13,289	$12,479	$12,365
PE	$11,151	$9,935	$8,966	$7,685	$9,355	$8,054	$5,874	$7,562

Wind units in the four zones were assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[29] Renewable energy credits were approximately 30 percent of the total net revenue of an onshore wind installation.

Table 7-21 RECs revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
AEP	$37,956	$41,971	$30,518	$12,681	$15,679	$18,030	$23,127	$34,136
APS	$36,437	$33,539	$26,854	$12,202	$15,350	$14,957	$22,491	$31,896
COMED	$40,539	$41,676	$28,828	$13,526	$15,102	$18,602	$23,227	$38,802
PE	$41,808	$39,913	$30,101	$12,811	$15,746	$14,956	$21,621	$32,326

In 2021, a new onshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. This has been the consistent result for a new wind installation for the entire period of the analysis.

Wind projects that are currently operating or under construction may have a different financing structure, require a lower rate of return, or have other factors that are not captured in the new entrant analysis presented in this section.

Table 7-22 Percent of 20-year levelized total costs recovered by onshore wind net revenue (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
AEP	76%	64%	45%	48%	55%	45%	37%	49%
APS	76%	56%	41%	48%	56%	38%	36%	46%
COMED	72%	58%	40%	47%	43%	43%	36%	51%
PE	92%	67%	45%	50%	56%	37%	34%	45%

27 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
28 PJM Planning. Class Average Capacity Factors Wind and Solar Resources. (Eff. June 1, 2017). <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.
29 RECs prices obtained from Evolution Markets, Inc.

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly assuming the unit generated at a 45 percent capacity factor.

Offshore wind energy market net revenues were higher as a result of higher energy prices.

Table 7-23 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$201,681	$129,548	$96,525	$109,649	$137,203	$93,518	$72,895	$126,045	73%
DOM	$214,838	$146,781	$119,621	$123,938	$154,001	$108,748	$86,363	$168,310	95%
DPL	$220,030	$145,044	$105,338	$120,842	$153,382	$99,180	$81,736	$149,175	83%

The new entrant offshore wind installation is based on a 45 percent capacity factor (derating factor) for defining the MW offered in the capacity market.

Table 7-24 Capacity market net revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	$29,793	$25,402	$22,926	$19,651	$29,545	$26,146	$25,943	$28,726
DOM	$14,017	$21,658	$15,020	$15,590	$23,948	$20,549	$14,050	$18,682
DPL	$29,793	$25,402	$22,926	$19,651	$29,298	$25,923	$25,908	$28,726

The offshore wind unit in ACEC was assumed to receive NJ wind RECs. The offshore wind unit in DOM and DPL was assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[30] Renewable energy credits accounted for 18 percent of the total net revenue of an off shore wind installation.

Table 7-25 RECs revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	$63,080	$63,891	$47,310	$20,176	$24,834	$26,247	$38,150	$61,260
DOM	$62,616	$62,607	$46,082	$19,225	$23,931	$26,087	$37,914	$61,252
DPL	$62,616	$62,607	$46,082	$19,225	$23,931	$26,087	$37,914	$61,252

In 2021, a new offshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the three zones analyzed.

Table 7-26 Percent of 20-year levelized total costs recovered by offshore wind net revenue (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	43%	32%	24%	22%	28%	21%	19%	28%
DOM	43%	34%	26%	23%	30%	22%	20%	32%
DPL	46%	34%	25%	23%	30%	21%	21%	31%

30 RECs prices obtained from Evolution Markets, Inc.

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone with an installed capacity greater than 3 MW.[31]

Solar energy market net revenues were higher as a result of significantly higher energy prices.

Table 7-27 Energy market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$67,446	$48,285	$38,762	$38,022	$41,772	$32,636	$23,716	$41,917	77%
DOM	-	-	$70,026	$68,150	$78,189	$59,472	$45,177	$90,539	100%
DPL	-	-	$45,546	$50,740	$61,773	$44,687	$33,323	$51,578	55%
JCPLC	$61,850	$41,551	$33,986	$36,414	$39,433	$30,189	$23,599	$41,144	74%
PSEG	$61,548	$47,830	$39,380	$40,979	$43,469	$34,047	$25,767	$45,977	78%

The new entrant solar installation analysis is based on a 42.0 percent capacity factor (derating factor) for defining the MW offered in the capacity market.[32]

Table 7-28 Capacity market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	$27,807	$23,708	$21,398	$18,341	$27,575	$24,403	$24,213	$26,811
DOM	-	-	$14,018	$14,551	$22,352	$19,179	$13,113	$17,437
DPL	-	-	$21,398	$18,341	$27,345	$24,195	$24,181	$26,811
JCPLC	$27,807	$23,708	$21,398	$18,341	$27,200	$23,714	$23,911	$26,809
PSEG	$30,478	$25,593	$28,234	$30,828	$33,260	$25,025	$24,515	$29,100

The solar installation was assumed to receive the highest of the DC, MD or NJ Solar REC, based on locational eligibility, for the purposes of calculating RECs revenue.[33] Renewable energy credits ranged from 59 percent of the total net revenue of a solar installation in DPL to 82 percent of the total net revenue of a solar installation in ACEC.

Table 7-29 RECs revenue for a solar installation (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	$240,050	$325,643	$373,683	$285,895	$273,161	$313,056	$292,165	$305,389
DOM	-	-	$101,679	$20,760	$18,364	$99,084	$150,493	$154,772
DPL	-	-	$74,619	$17,514	$15,804	$85,624	$121,982	$117,907
JCPLC	$222,593	$280,457	$332,265	$267,345	$258,291	$286,300	$281,980	$294,745
PSEG	$213,746	$303,612	$379,054	$294,273	$279,286	$319,285	$312,318	$317,419

In 2021, a new solar installation would have received sufficient net revenue to cover levelized total costs in all zones analyzed as a result of high energy and RECs revenue.

Solar projects that are currently operating or under construction may have a different financing structure, require a lower rate of return, or have other factors that are not captured in the new entrant analysis presented in this section.

Table 7-30 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year): 2014 through 2021

Zone	2014	2015	2016	2017	2018	2019	2020	2021
ACEC	142%	170%	198%	170%	147%	152%	180%	244%
DOM	-	-	85%	51%	51%	73%	110%	171%
DPL	-	-	65%	43%	45%	63%	95%	128%
JCPLC	132%	148%	177%	160%	140%	139%	174%	237%
PSEG	129%	161%	204%	182%	153%	155%	191%	256%

31 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
32 PJM Planning. Class Average Capacity Factors Wind and Solar Resources. (Eff. June 1, 2017). <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.
33 RECs prices obtained from Evolution Markets, Inc.

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 87 percent of their total costs in the BGE Zone and PSEG Zone, and 46 percent of total costs in the COMED Zone, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered 99 percent of their total costs on a cumulative basis in the BGE Zone and PSEG Zone and 58 percent of total costs in the COMED Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation, ignoring the benefits of competition on reducing costs and improving technology.

Figure 7-9 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CC that began operation on January 1, 2007, and a new entrant CC that began operation on January 1, 2012. The solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-9 Historical new entrant CC revenue adequacy: 2007 through 2021 and 2012 through 2021[34]

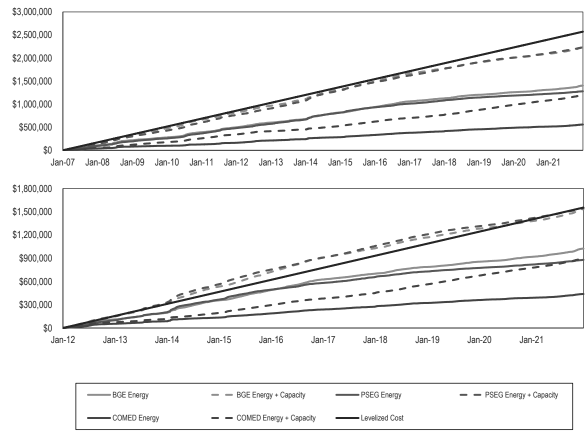


Table 7-31 shows the percent of levelized total costs recovered.

Table 7-31 Percent of levelized total costs recovered

	2007 CC	2012 CC
BGE	87%	99%
COMED	46%	58%
PSEG	87%	99%

Assumptions used for this analysis are shown in Table 7-32.

Table 7-32 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$20,016	$20,126
End of Life Value	$0	$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Cost of Equity (%)	12.0%	12.0%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years
IRR (%)	12.0%	12.0%

34 The gas pipeline pricing points used in this analysis are Zone 6 non-NY for BGE, Chicago City Gate for COMED, and Texas Eastern M3 for PSEG.

Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed and variable costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical and may be volatile when affected by exogenous forces. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Higher demand, higher energy prices, and higher spreads against fuel costs meant that units ran with higher margins and for more hours in 2021 than in 2020. High demand hours result in less efficient units setting prices, which results in higher net revenues for more efficient units. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue in the PJM design. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. A forward looking estimate of expected energy and ancillary services net revenues is a preferred method for defining the offset in the capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in new and existing units.

The returns earned by investors in generating units are a direct function of net revenues and the costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized total costs from Table 7-7. The results are shown in Table 7-33.[35]

Table 7-33 Internal rate of return sensitivity for CT and CC generators

	CT		CC	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$141,470	14.0%	$141,667	14.0%
Base Case	$134,297	12.0%	$132,378	12.0%
Sensitivity 2	$127,414	10.0%	$123,543	10.0%
Sensitivity 3	$120,833	8.0%	$115,167	8.0%
Sensitivity 4	$114,563	6.0%	$107,255	6.0%
Sensitivity 5	$108,614	4.0%	$99,810	4.0%
Sensitivity 6	$102,993	2.0%	$92,834	2.0%

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 7-34 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls.

Table 7-34 Debt to equity ratio sensitivity for CT and CC assuming 20-year debt term and 12 percent internal rate of return

	Equity as a percent of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$139,442	$139,164
Sensitivity 2	55%	$136,850	$135,739
Base Case	50%	$134,297	$132,378
Sensitivity 3	45%	$131,782	$129,079
Sensitivity 4	40%	$129,307	$125,843
Sensitivity 5	35%	$126,871	$122,670
Sensitivity 6	30%	$124,477	$119,561

Table 7-35 shows the impact of a range of capital costs on the levelized annual revenue requirement for the CT and the CC technologies. Costs vary significantly by location across PJM and even within PJM zones.

35 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt to equity capital structure with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC plant. An annual rate of cost inflation of 2.5 percent was used in all calculations.

Table 7-35 Capital cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of base case capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of base case capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$269,272	90.0%	$125,063	$920,360	90.0%	$121,756
Sensitivity 2	$284,231	95.0%	$129,680	$971,491	95.0%	$127,067
Base Case	$299,191	100.0%	$134,297	$1,022,622	100.0%	$132,378
Sensitivity 3	$314,151	105.0%	$138,913	$1,073,753	105.0%	$137,689
Sensitivity 4	$329,110	110.0%	$143,530	$1,124,884	110.0%	$143,000
Sensitivity 5	$344,070	115.0%	$148,147	$1,176,015	115.0%	$148,312
Sensitivity 6	$359,029	120.0%	$152,763	$1,227,147	120.0%	$153,623

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational to operate a unit whenever the price is greater than its short run marginal costs. It is rational for an owner to continue to operate a unit rather than retire the unit if the unit is covering or is expected to cover its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit rather than retire the unit if the unit is not covering and is not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of incremental investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. For example, APIR may reflect investments in environmental technology which were made in prior years to keep units in service. These costs are sunk costs.

The MMU calculated actual unit specific energy and ancillary service net revenues for a range of technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM energy and ancillary service markets alone provide sufficient incentive for continued operations in PJM markets. Energy and ancillary service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include day-ahead and balancing market energy revenues, less short run marginal costs, plus any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, synchronized reserves, black start service, and reactive revenues.

The MMU calculated avoidable costs by unit type in dollars per MW-year.[36]

The PJM capacity market design provides supplemental signals to the market based on the locational and forward looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2020/2021 and 2021/2022 Delivery Years, reflecting commitments made in base residual auctions (BRA) and subsequent incremental auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM markets in 2021. Any unit with a significant portion of installed capacity

36 Avoidable costs provided by Pasteris Energy, Inc.

designated as FRR committed was excluded from the analysis.[37] For units exporting capacity, the applicable BRA clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the capacity market. The analysis is on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. As required by FERC, net revenues for units other than nuclear are calculated using units' price-based offers for technologies, unless the unit is cost-capped or the price-based offer is less than fuel plus environmental costs.[38] For nuclear units, public data on revenues and costs are used.

The unit specific energy and ancillary net revenues, avoidable costs and capacity revenues, on which the class averages shown in Table 7-36 are based, include a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile.

Table 7-36 shows energy and ancillary service net revenues by quartile for select technology classes.[39] Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivered costs for input fuels. Unlike the other technologies, nuclear data is from public sources in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP from the relevant node as shown in Table 7-39, adjusted by the class average equivalent availability factor. Nuclear unit capacity revenue assumes that the unit cleared its full installed capacity at the BRA locational clearing price as shown in Table 7-40.

Table 7-36 also includes new entrant theoretical energy market net revenue from Table 7-9, Table 7-11, Table 7-13, Table 7-15, and Table 7-17 for comparison purposes. As an example, for the CC plants, the predominant form of new entry in PJM, some existing resources in the top quartile of net revenue, earn net revenues that are comparable to the theoretical new entrant net revenues. This supports the conclusion that the theoretical new entrant results are a good representation of the performance of actual new entrants and existing plants with comparable technologies. The results for existing units vary based on location, technology and actual performance.

Table 7-36 Net revenue by quartile for select technologies: 2021

		($/MW-Yr)										
	Total	Energy and ancillary service net revenue				Capacity revenue			Energy, ancillary, and capacity revenue			
Technology	Installed Capacity (ICAP)	New entrant	First quartile	Median	Third quartile	First quartile	Median	Third quartile	New entrant	First quartile	Median	Third quartile
CC - Combined Cycle	62,125	$89,268	$5,561	$27,779	$52,087	$39,235	$40,923	$60,235	$136,323	$54,525	$76,999	$102,912
CT - Aero Derivative	6,086	$49,943	$2,206	$6,946	$15,817	$40,038	$57,412	$63,313	$99,008	$51,114	$65,966	$72,583
CT - Industrial Frame	21,441		$4	$2,192	$5,950	$38,480	$40,591	$61,201		$40,731	$47,696	$63,762
Coal Fired	38,816	$36,856	$5,941	$27,209	$46,472	$33,390	$38,549	$40,411	$85,521	$45,914	$60,784	$89,318
Diesel	183	$8,559	$464	$10,590	$23,294	$39,363	$41,446	$57,777	$62,013	$40,235	$50,776	$73,392
Hydro	1,702		$71,952	$120,376	$236,968	$0	$28,591	$39,900		$88,939	$154,528	$236,968
Nuclear	30,351	$307,847	$250,049	$272,263	$304,772	$42,574	$63,272	$69,635	$356,829	$313,321	$338,010	$349,613
Oil or Gas Steam	5,992		($3,123)	($784)	$635	$634	$41,260	$56,793		$3,364	$42,988	$57,914
Pumped Storage	8,004		$8,259	$10,841	$16,119	$37,058	$41,240	$42,663		$45,199	$53,132	$57,359
Solar	4,035	$54,231	$41,835	$47,880	$65,421	$0	$0	$11,484	$79,624	$42,681	$51,918	$75,379
Wind	9,989	$74,030	$72,967	$97,137	$182,405	$0	$4,770	$13,735	$82,671	$79,830	$115,696	$183,513

37 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

38 154 FERC ¶ 61,151 at P 59.

39 The quartile numbers in the table are the dividing lines between the quartiles. The first quartile result means that 25 percent of units have lower net revenues, the median result means that 50 percent of units have lower net revenues and the third quartile result means that 75 percent of units have lower net revenues.

Table 7-37 shows the percent of avoidable costs covered by net revenue from PJM energy and ancillary services markets by quartiles. In 2021, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. After including capacity revenues, net revenues from all markets cover avoidable costs for even the first quartile of most technology types, although this is not the case for every individual unit and it is not the case for coal units.

The analysis of nuclear plants includes publicly available data on energy market prices, capacity prices, and an estimate of annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's average across all U.S. nuclear plants.[40] [41] The NEI annual avoidable costs used in the analysis are for 2020, the most recent data available.

Table 7-37 Avoidable cost recovery by quartile: 2021

		Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Total Installed Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	62,125	24%	104%	240%	181%	366%	500%
CT - Aero Derivative	6,086	6%	18%	42%	134%	171%	185%
CT - Industrial Frame	21,441	0%	6%	16%	107%	125%	166%
Coal Fired	38,816	10%	56%	96%	89%	125%	163%
Diesel	183	2%	46%	101%	175%	220%	319%
Hydro	1,702	100%	100%	100%	100%	100%	100%
Nuclear	30,351	113%	119%	136%	141%	149%	158%
Oil or Gas Steam	5,992	0%	0%	3%	15%	182%	245%
Pumped Storage	8,004	22%	32%	100%	121%	134%	165%
Solar	4,035	778%	893%	1,213%	796%	963%	1,404%
Wind	9,989	252%	340%	642%	266%	412%	663%

Table 7-38 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets from 2011 through 2021. In 2021, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, a significant change from 2020 for both coal and nuclear units.[42]

Table 7-38 Proportion of units recovering avoidable costs: 2011 through 2021

	Units with full recovery from energy and ancillary net revenue											Units with full recovery from all markets										
Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	64%	67%	50%	85%	79%	79%	95%	88%	93%	89%	98%	90%	93%	83%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	46%	42%	2%	100%	96%	76%	98%	100%	99%	100%	99%	96%	96%	89%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	30%	21%	2%	99%	98%	83%	100%	100%	100%	100%	96%	92%	86%	84%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	2%	2%	22%	82%	36%	54%	83%	64%	40%	36%	63%	31%	5%	66%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	11%	37%	25%	100%	100%	77%	100%	100%	100%	100%	97%	91%	89%	83%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	90%	72%	95%	81%	77%	97%	98%	100%	100%	97%	98%	100%	74%	95%
Nuclear	-	-	50%	94%	17%	6%	17%	53%	0%	0%	88%	-	-	61%	100%	56%	17%	50%	88%	81%	0%	100%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	73%	6%	10%	92%	78%	86%	85%	91%	88%	81%	76%	66%	34%	67%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	29%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Solar	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	100%	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	100%
Wind	88%	85%	96%	93%	92%	89%	93%	91%	88%	79%	94%	88%	85%	96%	93%	92%	89%	93%	91%	89%	79%	95%

40 Operating costs from: Nuclear Energy Institute (November, 2021). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

41 The NEI costs for Hope Creek and Salem plants were both treated as those associated with a two unit configuration because all three units are located in the same area.

42 Analysis excludes Catawba 1 which joined PJM with the integration of DEOK.

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[43] [44] The analysis includes the most recent operating cost data and incremental capital expenditure data for single unit plants and multi unit plants published by NEI, for 2020.[45] This is likely to result in conservatively high costs for the forward looking analysis. NEI average operating costs have decreased since their peak in 2012 (a 12.8 percent decrease from 2012 through 2020 for all plants including single and multiple unit plants).[46] NEI average incremental capital expenditures have decreased since their peak in 2012 (a 49.1 percent decrease from 2012 through 2020 for all plants including single and multiple unit plants).[47] NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[48] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were then at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs based on current year prices.[49] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Although energy prices in 2019 were lower than in 2016, higher capacity market revenues more than offset the difference. Energy prices in 2020 were lower than 2019 prices, but forward energy prices for 2022 are higher than historical energy prices for all years since 2009. The result is that nuclear plant energy revenues based on forward period prices are higher than in previous years. The results for nuclear plants are also sensitive to changes in costs and whether actual unit costs are less than or greater than the benchmark NEI data.

Table 7-39 includes the publicly available data on energy market prices, Table 7-40 and Table 7-41 show capacity market prices and Table 7-42 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.[50] The analysis excludes the Cook nuclear units, the Catawba 1 nuclear unit, and the North Anna and Surry nuclear units. The Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.[51] Catawba 1 is not in PJM but is pseudo tied to PJM. North Anna 1 and 2 and Surry 1 and 2 are part of the Dominion FRR for the 2022/2023 Delivery Year.

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.

43 Operating costs from: Nuclear Energy Institute (November, 2021). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context-2021.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

44 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

45 NEI also provides average costs by plant run by operators with one plant or multiple plants, by market, and by type of nuclear reactor. Plants run by operators with multiple plants have lower average costs than plants run by operators with a single plant. Plants participating in wholesale markets have lower average costs than plants in regulated markets. PWR reactors have lower average costs than BWR reactors.

46 Operating costs in this paragraph are operating costs as specified by NEI and do not include fuel costs or capital expenditures. Operating costs for single unit plants increased by $1.73/MWh, or 7.0 percent, from 2019 to 2020. Operating costs for multiple unit plants decreased by $0.57/MWh, or 3.4 percent, from 2019 to 2020.

47 Capital expenditures have decreased 44.1 percent since 2012 for single unit plants and 49.5 percent for multiple unit plants.

48 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating at a capacity factor of 100 percent. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.09 per MWh for a nuclear power plant operating at a capacity factor of 0.918 percent.

49 The MMU submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program.* Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring.*

50 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

51 See "Resources Designated in 2021/2022 FRR Capacity Plans as of May 1, 2018," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-resources-designated-in-frr-plans.ashx?la=en>.

Table 7-39 Nuclear unit day-ahead LMP: 2008 through 2021

	ICAP	Average DA LMP ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35	$26.22	$20.33	$37.07
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11	$22.88	$18.23	$33.74
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96	$22.19	$17.66	$32.81
Calvert Cliffs	1,708	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79	$28.00	$21.88	$41.24
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54	$37.34
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25	$23.41	$18.73	$34.32
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93	$22.45	$17.32	$30.16
LaSalle	2,271	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19	$22.75	$18.14	$33.54
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08	$22.68	$17.31	$31.05
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44	$27.39	$21.06	$39.99
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	$34.03	$23.68	$18.07	$32.36
Peach Bottom	2,347	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63	$21.58	$16.93	$30.77
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76	$20.49	$37.76
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54	$21.13	$15.95	$31.39
Salem	2,328	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90	$22.43	$17.32	$30.12
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50	$26.65	$20.41	$39.30
Susquehanna	2,520	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42	$21.08	$16.03	$30.36
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76	$23.47	$19.07	$39.58

Table 7-40 BRA capacity market clearing prices ($/MW-Day): 2007/2008 through 2022/2023[52 53]

	ICAP	BRA Capacity Price ($/MW-Day)															
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	$50
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Calvert Cliffs	1,708	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98
LaSalle	2,271	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	-
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-	-
Peach Bottom	2,347	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Salem	2,328	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	-
Susquehanna	2,520	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	-

52 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>. For the 2022/2023 Delivery Year, Surry is part of Dominion FRR.

53 North Anna and Surry are in Dominion FRR beginning with the 22/23 Delivery Year.

Table 7-41 Nuclear unit capacity market revenue ($/MWh): 2008 through 2022[54 55]

	ICAP	Capacity Revenue ($/MWh)														
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.84	$5.12	$3.92
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46
Calvert Cliffs	1,708	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.62	$4.09	$5.29	$5.13
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.84	$5.94	$4.51
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67
LaSalle	2,271	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.84	$5.12	NA
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	NA	NA	NA	NA	NA
Peach Bottom	2,347	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.84	$5.94	$4.51
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46
Salem	2,328	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.84	$5.12	NA
Susquehanna	2,520	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.08	$5.29	$5.13
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.08	$5.29	NA

Table 7-42 Nuclear unit costs: 2008 through 2020[56 57]

	ICAP	NEI Costs ($/MWh)												
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	NA	NA	NA
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	NA	NA

In 2020, no nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy prices. In 2021, all nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of higher energy prices.

Table 7-43 shows the surplus or shortfall in $/MWh for the 16 nuclear plants in PJM and Oyster Creek and Three Mile Island calculated using historic LMP and cost data. In 2021, all nuclear plants more than covered their fuel costs, operating costs, and capital expenditures as a result of higher energy prices. The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[58] Unforced capacity is determined using the annual class average EFORd rate.

54 Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the annual class average capacity factor. Class average EFORd and capacity factor is from *2021 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market.

55 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

56 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>.

57 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

58 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market as a result of decisions by plant owners about how to offer the plants. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not reflect the economic viability of the plants unless the plants offer accurate net avoidable costs and fail to clear. This analysis is intended to define whether the plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices, then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Quad Cities and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[59] Quad Cities did not clear in the 2020/2021 Auction.[60] Dresden and most of Byron did not clear in the 2021/2022 Auction.[61] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[62] Byron, Dresden, and Quad Cities did not clear in the 2022/2023 Auction.[63]

Nuclear unit revenue is a combination of energy market revenue, ancillary market revenue and capacity market revenue. Negative energy market prices do not have a significant impact on nuclear unit revenue. Since 2014, negative energy market prices have affected nuclear plants' annual total revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant total revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, an average of 0.0 percent and a maximum of 0.0 percent in 2018, an average of 0.0 percent and a maximum of 0.2 percent in 2019, an average of 0.1 percent and a maximum of 1.7 percent in 2020, and an average of 0.0 percent and a maximum of 0.3 percent in 2021.[64]

In 2021, all nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of higher energy prices.

Table 7-43 Nuclear unit surplus (shortfall) based on public data: 2008 through 2021

	ICAP	Surplus (Shortfall) ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.4)	$2.6	$13.9	$3.7	($2.6)	$15.4
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.1)	($1.5)	$6.0	$3.9	$0.1	$15.6
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.5)	($2.7)	$5.8	$3.2	($0.5)	$14.6
Calvert Cliffs	1,708	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.3	$6.1	$16.3	$5.4	($0.9)	$19.7
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.2)	($15.0)	$3.9
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.5)	($0.0)	$7.2	$4.6	$0.7	$16.3
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($2.0)	$1.6	$12.3	$1.7	($2.2)	$11.4
LaSalle	2,271	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.5)	($1.8)	$6.0	$3.8	($0.1)	$15.4
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.1)	$1.5	$12.1	$1.7	($2.5)	$12.0
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.8	($2.0)	$18.2
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA	NA	NA
Peach Bottom	2,347	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.8	$0.7	($2.7)	$11.9
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.3)	$1.9	($5.8)	($15.1)	$4.3
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.4)	$4.4	$2.1	($2.3)	$13.2
Salem	2,328	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.3)	$1.3	$11.9	$1.4	($2.5)	$11.1
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.6	$4.5	$16.0	$4.1	($2.6)	$17.6
Susquehanna	2,520	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.1	($1.4)	($6.6)	$8.9
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA	NA

59 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
60 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
61 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.
62 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>.
63 NuclearNewswire. "Byron, Dresden, Quad Cities Fail to Clear in PJM Capacity Auction," (June 8, 2021) <https://www.ans.org/news/article-2967/byron-dresden-quad-cities-fail-to-clear-in-pjm-capacity-auction/>.
64 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2022, 2023 and 2024 and known capacity market prices for 2022. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values. Nuclear plants may sell their output at a range of forward prices and for a range of future years.

Table 7-44 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2022 through 2024. Capacity revenues are not presented for calendar year 2023 because the 2023/2024 BRA has not been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[65] Forward prices are as of January 3, 2022. The capacity prices are known based on PJM capacity auction results.

Table 7-44 Forward prices in PJM energy markets, capacity revenue, and annual costs

		Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)		2020 NEI Costs ($/MWh)		
	ICAP (MW)	2022	2023	2024	Reactive	2022	2023	Fuel	Operating	Capital
Beaver Valley	1,808	$41.61	$38.89	$37.82	$0.25	$5.12	$3.92	$5.76	$16.43	$4.84
Braidwood	2,337	$39.02	$36.57	$35.54	$0.25	$8.66	$5.46	$5.76	$16.43	$4.84
Byron	2,300	$37.40	$35.07	$34.10	$0.21	$8.66	$5.46	$5.76	$16.43	$4.84
Calvert Cliffs	1,708	$45.89	$42.92	$41.72	$0.20	$5.29	$5.13	$5.76	$16.43	$4.84
Davis Besse	894	$41.40	$38.69	$37.61	$0.25	$5.94	$4.51	$5.76	$26.33	$7.55
Dresden	1,797	$39.68	$37.19	$36.15	$0.33	$8.66	$5.46	$5.76	$16.43	$4.84
Hope Creek	1,172	$36.59	$34.35	$33.39	$0.43	$7.87	$5.67	$5.76	$16.43	$4.84
LaSalle	2,271	$38.81	$36.37	$35.35	$0.18	$8.66	$5.46	$5.76	$16.43	$4.84
Limerick	2,242	$36.93	$34.63	$33.68	$0.14	$7.87	$5.67	$5.76	$16.43	$4.84
North Anna	1,892	$45.05	$42.14	$40.96	$0.17	$5.12	NA	$5.76	$16.43	$4.84
Peach Bottom	2,347	$36.74	$34.46	$33.51	$0.29	$7.87	$5.67	$5.76	$16.43	$4.84
Perry	1,240	$42.35	$39.60	$38.51	$0.25	$5.94	$4.51	$5.76	$26.33	$7.55
Quad Cities	1,819	$35.89	$33.63	$32.70	$0.18	$8.66	$5.46	$5.76	$16.43	$4.84
Salem	2,328	$36.53	$34.29	$33.34	$0.13	$7.87	$5.67	$5.76	$16.43	$4.84
Surry	1,676	$44.57	$41.70	$40.54	$0.17	$5.12	NA	$5.76	$16.43	$4.84
Susquehanna	2,520	$35.55	$33.27	$32.36	$0.29	$5.29	$5.13	$5.76	$16.43	$4.84

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant.

Based on the FERC order about inclusion of maintenance expense in energy offers, major maintenance costs can no longer be included in gross ACR values.[66] The MMU calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant with major maintenance included in avoidable costs and with major maintenance excluded from avoidable costs. For the case including major maintenance, gross ACR is NEI total cost including fuel, operating cost, and incremental capital expenditures. For the case excluding major maintenance, gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM, given that NEI does not provide a breakout of major maintenance. NEI incremental capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

All generating plants including nuclear plants must cover their gross avoidable costs, including major maintenance, to remain economically viable. All of the MMU analysis of nuclear plant economics includes gross avoidable costs as reported by NEI unless explicitly stated otherwise.

In Table 7-45, the capacity price required to cover avoidable costs in $ per MWh is calculated by taking the total NEI costs in $ per MWh and subtracting the total expected energy and ancillary services revenues in $ per MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average

65 Forward prices on January 3, 2022. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2021 data.
66 See 167 FERC ¶ 61,030 at P 41.

equivalent availability factor. Total expected ancillary services revenue is reactive capability revenue.[67] The capacity price required to cover avoidable costs in $ per MW-day is calculated by multiplying the required price in $ per MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-45, for 2022, using forward prices as of January 3, 2022, the capacity price required to cover avoidable costs is $0/MW-day for all units using NEI data as reported including capital expenditures, and is $0/MW-day for all plants, excluding capital expenditures as a proxy for major maintenance.[68] Net revenues based on forward energy prices are greater than or equal to avoidable costs in 2022 without any contribution from capacity market revenues.

Table 7-45 Net ACR

	ICAP (MW)	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
		2022	2023	2024	2022	2023	2024	2022	2023	2024
Beaver Valley	1,808	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Braidwood	2,337	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Byron	2,300	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Calvert Cliffs	1,708	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$0.00	$0.71	$1.79	$0.00	$15.57	$39.41	$0.00	$0.00	$0.00
Dresden	1,797	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hope Creek	1,172	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
LaSalle	2,271	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Limerick	2,242	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
North Anna	1,892	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Peach Bottom	2,347	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Perry	1,240	$0.00	$0.00	$0.89	$0.00	$0.00	$19.52	$0.00	$0.00	$0.00
Quad Cities	1,819	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Salem	2,328	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Surry	1,676	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Susquehanna	2,520	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table 7-46 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2020 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-46 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

Changes in forward energy market prices can significantly affect expected profitability of nuclear plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that all plants are expected to cover their annual avoidable costs in 2022.

Hope Creek, Quad Cities, and Salem all currently receive subsidies. Braidwood, Byron, Dresden, and LaSalle will receive a subsidy if necessary to meet a target net revenue value, in dollar per MWh, from the energy and capacity markets. Based on forward prices as of January 3, 2022, and NEI average costs, none of these units need a subsidy, and therefore zero subsidy values are included for these plants in Table 7-46.

67 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.
68 PJM's tariff definition of avoidable costs excludes major maintenance. PJM includes major maintenance costs in the definition of short run marginal costs in energy offers.

Table 7-46 Nuclear unit forward annual surplus (shortfall)[69 70 71 72 73]

	ICAP (MW)	Surplus (Shortfall) ($/MWh) 2022	Subsidy ($/MWh) 2022	Surplus (Shortfall) Excluding Subsidy ($ in millions) 2022	Surplus (Shortfall) Including Subsidy ($ in millions) 2022
Beaver Valley	1,808	$19.94		$291.6	$291.6
Braidwood	2,337	$20.90	$0.00	$394.8	$394.8
Byron	2,300	$19.24	$0.00	$357.8	$357.8
Calvert Cliffs	1,708	$24.36		$336.3	$336.3
Davis Besse	894	$7.95		$58.0	$58.0
Dresden	1,797	$21.63	$0.00	$314.2	$314.2
Hope Creek	1,172	$17.86	$10.00	$169.3	$263.5
LaSalle	2,271	$20.63	$0.00	$378.6	$378.6
Limerick	2,242	$17.91		$324.7	$324.7
North Anna	1,892	$23.30		$356.4	$356.4
Peach Bottom	2,347	$17.87		$339.1	$339.1
Perry	1,240	$8.90		$89.9	$89.9
Quad Cities	1,819	$17.70	$16.50	$260.3	$501.7
Salem	2,328	$17.50	$10.00	$329.5	$516.7
Surry	1,676	$22.83		$309.3	$309.3
Susquehanna	2,520	$14.10		$287.8	$287.8

Units At Risk

The definition of units at risk of retirement is units that are not expected to recover their avoidable costs from market revenues. The additional units at risk as a result of environmental regulations at the federal or state level are not identified here.

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover and are expected to continue to fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement.[74] The profile of units that are not expected to cover their avoidable costs over the next three years is shown in Table 7-47. These units are considered at risk of retirement.[75]

The analysis compares expected energy and capacity market revenues to ACR values over the period 2022-2024. Bus level forward LMPs are based on forward prices with a basis adjustment for the specific plant locations.[76] Forward prices are as of January 3, 2022. The capacity revenues for 2022 are carried forward for calendar year 2023 and 2024 because neither the 2023/2024 nor the 2024/2025 auctions have been run.

Based on these criteria, a total of 2,230 MW of capacity are at risk of retirement, in addition to the units that are currently planning to retire.[77] This capacity consists entirely of peaker units.

The significant increase in historical and forward energy market prices affected the financial results for both coal and nuclear units. No coal plants are defined to be at risk of retirement based on the identified financial criteria. No nuclear plants are defined to be at risk of retirement based on the identified financial criteria. The maximum Net ACR for all multiple unit plants in 2022 through 2024 is $0/MW-Day.

Table 7-47 Profile of units at risk of retirement

	No. Units	ICAP (MW)	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/Mwh)
Total	31	2,230	49	14,541

69 Report to the General Assembly in Compliance with Section 1-75(d-5) of the Illinois Power Agency Act 20 ILCS 3855/1-75(d-5)(F)(2). Illinois Commerce Commission. August 2019. The report finds that while total ZECs payments are limited by rate impact caps and volume caps, the law's limitation does not unduly constrain the procurement of ZECs.

70 *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Hope Creek, Order Determining the Eligibility of Hope Creek Nuclear Generator to Receive ZECs*, BPU Docket No. ER20080559 (April 27, 2021). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 1, Order Determining the Eligibility of Salem Unit 1 Nuclear Generator to Receive ZECs*, BPU Docket No. ER20080557 (April 27, 201). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 2, Order Determining the Eligibility of Salem Unit 2 Nuclear Generator to Receive ZECs*. BPU Docket No. ER20080557 (April 27, 2021).

71 North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year.

72 The subsidy value for Braidwood, Byron, Dresden, and LaSalle is calculated by taking the applicable Baseline Cost less forward energy prices and known capacity prices.

73 The Illinois Energy Transition Act, SB 2408.

74 FRR units and units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.

75 Units expected to continue operations for reasons not directly related to market prices are not considered at risk of retirement.

76 Forward prices on January 4, 2021. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2020 data.

77 Units at risk of retirement analysis is based on the default unit type ACR provided by Pasteris Energy, Inc.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. The investments required for environmental compliance have affected offer behavior in the capacity market. Expectations about the cost and life of such investments and about future capacity and energy prices have affected retirement decisions. The markets have also provided incentives for new, lower emission units to enter.

Overview

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[1] On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.[2] The list of coal steam units subject to MATS, however, remains in place.[3] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS. The EPA's May 22, 2020, finding is under review pursuant to Executive Order 13990.
- **Air Quality Standards (NO_x and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[4] On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[5]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[6] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[7] RICE do not have to meet the same emissions standards if they are emergency stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

  PJM does not prevent emergency stationary RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.
- **Greenhouse Gas Emissions.** On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan (CPP), which ACE had replaced.[8] Neither the ACE nor CPP is currently effective.
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires

1 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).
2 *See National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 31286.
3 *Id.* at 31291.
4 CAA § 110(a)(2)(D)(i)(I).
5 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
6 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).
7 See 40 CFR § 63.6640(f).
8 American Lung Association et al. v. EPA, No. 19-1140.

that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[9]

- **Waters of the United States.** On November 18, 2021, the EPA and the Department the Army announced the signing of a proposed rule to revise the definition of "waters of the United States" to restore the pre 2015 definition of "waters of the United States." The proposed rule, if adopted, would make permanent the pre 2015 regulatory regime for interpreting WOTUS that is now effective.
- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. The EPA has recently been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result.
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[10] The EPA has adopted significant changes to the implementing regulations that will require closing non compliant impoundments, and, potentially, the host power plant. The EPA is implementing a process for extensions to as late as October 17, 2028. The EPA is reviewing applications received from PJM plant owners. So far, the EPA has proposed to reject applications for Gavin and Clifty Creek, and proposed to grant, with conditions, an application from Spurlock.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia that applies to power generation facilities. New Jersey rejoined on January 1, 2020.[11] Virginia joined RGGI on January 1, 2021, and Pennsylvania is preparing to join.[12] [13] The auction price in the December 1, 2021, auction was at the administrative price cap (Cost Containment Reserve (CCR) trigger price) of $13.00 per short ton, or $14.33 per metric tonne.
- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis going forward. More than 10,000 MW of capacity are currently affected.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would increase by $24.52 per MWh or 65.0 percent for a new combustion turbine (CT) unit, $16.71 per MWh or 65.5 percent for a new combined cycle (CC) unit and $43.15 per MWh or 119.8 percent for a new coal plant (CP) for 2021.

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2021, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Virginia had a voluntary RPS in 2020, but a new mandatory RPS became effective on January 1, 2021. Indiana has voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $5.6 billion over the six year period from 2014 through 2019, an average annual RPS compliance cost of $936.7 million. The

9 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

10 42 U.S.C. §§ 6901 *et seq.*

11 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.

12 "Statement on Virginia Greenhouse Gas Rule," RGGI, (July 8, 2020) <https://www.rggi.org/news-releases/rggi-releases>.

13 Executive Order–2019-07. Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

compliance cost for 2019, the most recent year with almost complete data, was $1.2 billion.[14]

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of December 31, 2021, 93.5 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.8 percent of coal steam MW had some type of particulate control, and 94.6 percent of fossil fuel fired capacity had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 4.2 percent of total generation in PJM in 2021. RPS Tier I generation was 5.7 percent of total generation in PJM and RPS Tier II generation was 2.2 percent of total generation in PJM in 2021. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.

Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets.

Environmental requirements and initiatives at both the federal and state levels, and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources and the retirement of emitting resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables

14 The 2019 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, including supporting some emitting resources, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

But in the absence of a PJM market carbon price, a single PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor.

RECs are an important mechanism used by PJM states to implement environmental policy. RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data.

Existing REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $11.33 per tonne in Washington, DC to $20.48 per tonne in Maryland. The price of carbon implied by SREC prices ranges from $69.30 per tonne in Pennsylvania to $867.85 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in December 2021 of $14.33 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[15] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.71 per MWh.[16] The impact of an $800 per tonne carbon price would be $267.30 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market.

15 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

16 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.053070 tonne per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-7.

The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

If the states chose this policy option, PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. The results of the analysis would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state.

For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the six year period from 2014 through 2019 for the nine jurisdictions that had RPS was $936.7 million, or a total of $5.6 billion over six years. The RPS compliance cost for 2019, the most recent year for which there is almost complete data, was $1.2 billion.[17] RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $3.7 billion per year if the carbon price were $13.00 per short ton and emissions levels were five percent below 2021 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $13.00 per short ton would be about $2.4 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.[18]

The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology

17 The 2019 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

18 For more details, see the *2019 State of the Market Report for PJM*, Vol. II, Appendix H: "Environmental and Renewable Energy Regulations."

based standards for major sources and area sources of emissions.[19 20]

The CWA regulates discharges from point sources that affect water quality and temperature.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[21] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

The EPA's actions have affected and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.

On May 22, 2020, the EPA published a rule finalizing its Supplemental Cost Finding for the MATS, and the risk and technology review required by the CAA.[22] The EPA determined that the estimated cost to coal and oil fired power plants of complying with the MATS rule in 2015 outweighed the estimated quantifiable benefits attributable to regulating hazardous air pollutant (HAP) emissions in 2015.[23] The EPA determined that based on analysis of costs versus benefits it is not "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the Clean Air Act.[24 25] The immediate practical effect is limited because the emission standards and other requirements of the 2012 MATS rule remain in place and the list of coal and oil fired power plants regulated under Section 112 of the Act remains in place.[26] Removal of the appropriate and necessary finding creates the possibility of a challenge to the MATS rule if applied to the proposed construction or upgrade of a power plant.

On January 20, 2021, an executive order was issued stating national objectives "to listen to the science; to improve public health and protect our environment; to ensure access to clean air and water; to limit exposure to dangerous chemicals and pesticides; to hold polluters accountable, including those who disproportionately harm communities of color and low-income communities; to reduce greenhouse gas emissions; to bolster resilience to the impacts of climate change; to restore and expand our national treasures and monuments; and to prioritize both environmental justice and the creation of the well-paying union jobs necessary to deliver on these goals" ("Executive Order 13990").[27] The order directs government agencies to immediately review, and as appropriate and consistent with applicable law, "take action to address the promulgation of Federal regulations and other actions during the last 4 years that conflict with these important national objectives, and to immediately commence work to confront the climate crisis."[28] The May 22, 2021, supplemental finding on MATS is an action specified for review.[29]

On April 9, 2020, the EPA finalized a rule establishing a new sub category in the MATS with less stringent requirements for units fueled by eastern bituminous refuse coal, waste coal.[30] The rule allows four refuse coal plants, Grant Town Power Plant (Unit 1A and 1 B (40 MW each)) in West Virginia; and Colver Power Project (110 MW), Ebensburg Power Plant (50 MW), and Scrubgrass Generating Co. (Units 1 and 2 (42 MW each)) in Pennsylvania; to emit higher levels of acid gases and SO_2.[31] The EPA stated that it was concerned that units

19 42 U.S.C. § 7401 et seq. (2000).
20 The EPA defines a "major source" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.
21 42 U.S.C. §§ 6901 *et seq.*
22 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 31286.
23 *Id.* at 31299.
24 Michigan v. EPA, 135 S.Ct. 2699 (2015) (reversed EPA determination that cost does not have to be read into the definition of "appropriate").
25 85 Fed. Reg. at 31288.
26 *Id.* at 31291. The EPA explains (id.): "The Court's holding in New Jersey [517 F.3d 574 (D.C. Cir. 2008)] plainly states that CAA section 112(c)(9) 'unambiguously limit[s] EPA's discretion to remove sources, including EGUs, from the section 112(c)(1) list once they have been added to it.' 517 F.3d 574, 583 (D.C. Cir. 2008)."
27 *See* President Joseph R. Biden Jr., Executive Order 13990 re "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" ("Executive Order 13990").
28 *Id.* (Sec. 1).
29 *Id.* at Sec. 2(iv).
30 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Subcategory of Certain Existing Electric Utility Steam Generating Units Firing Eastern Bituminous Coal Refuse for Emissions of Acid Gas Hazardous Air Pollutants*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 20838 (April 15, 2020).
31 *Id.* at 20841.

would close and leave coal refuse piles, which are prone to smoldering and emit uncontrolled acid gases and other HAP.[32]

CAA: NAAQS/CSAPR

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

In January 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[33]

On March 15, 2021, in response to a court holding in *Wisconsin v. EPA*,[34] the EPA finalized increases to the good neighbor obligations (i.e. reduced allowable emissions) under the 2008 ozone NAAQS for 12 states.[35] Eleven of the affected states are PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The EPA determined that Tennessee's emissions budget "fully eliminated the state's significant contribution to downwind nonattainment and interference with maintenance of the 2008 ozone NAAQS."[36] For the remaining PJM states, projected 2021 emissions were found to contribute at or above a threshold of 1 percent of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states.[37] Starting with the 2021 ozone season for emissions trading under CSAPR, the new FIPs require power plants in the affected states (also including Louisiana and New York) to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program.[38] Participation in the more stringent new program would replace the obligation to participate in the existing CSAPR NO_x Ozone Season Group 2 Trading Program.[39] [40]

The EPA's new emissions budgets for each PJM state for each ozone season for 2021 through 2024, and beyond are shown in Table 8-1. Table 8-1 also includes the states budgets that would have been in effect had the rules not been revised.

Table 8-1 CSAPR NO_X ozone season group 3 state budgets: 2021 through 2024[41] [42]

	Emissions Budget (Tons)							
	Budget without revised rule				Revised Budget			
PJM State	2021	2022	2023	2024+	2021	2022	2023	2024+
Illinois	9,368	9,368	8,413	8,292	9,102	9,102	8,179	8,059
Indiana	15,856	15,383	15,357	12,232	13,051	12,582	12,553	9,564
Kentucky	15,588	15,588	15,588	15,588	15,300	14,051	14,051	14,051
Maryland	1,501	1,267	1,267	1,350	1,499	1,266	1,266	1,348
Michigan	13,898	13,459	11,182	10,968	12,727	12,290	9,975	9,786
New Jersey	1,346	1,346	1,346	1,346	1,253	1,253	1,253	1,253
Ohio	15,829	15,927	15,927	15,927	9,690	9,773	9,773	9,773
Pennsylvania	11,896	11,896	11,896	11,896	8,379	8,373	8,373	8,373
Virginia	4,664	4,274	4,361	4,025	4,516	3,897	3,980	3,663
West Virginia	15,165	15,165	15,165	15,165	13,334	12,884	12,884	12,884

Figure 8-1 shows average, monthly settled prices for NO_X and SO_2 emissions allowances including CSAPR related allowances for 2020 and 2021. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

32 *Id.* at 20847.

33 Section 126 of the CAA permits a downwind state to file a petition with the EPA to regulate the emissions from particular resources in another state. On October 5, 2018, EPA denied petitions filed under this provision filed by Delaware and Maryland. See *Response to Clean Air Act Section 126(b) Petitions From Delaware and Maryland*, EPA Docket No. EPA-HQ-OAR-2018-0295, 83 Fed. Reg. 50444 (Oct. 5, 2018). Delaware filed a petition requesting that the EPA regulate emissions from the Brunner Island coal plant in Pennsylvania, the Harrison coal plant in West Virginia, the Homer City coal plant in Pennsylvania and the Conemaugh coal plant in Pennsylvania. Maryland filed a petition requesting that the EPA regulate 36 generating units at coal plants located in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia. U.S. Court of Appeals for the D.C. Circuit Case No. 18-1285. On May 15, 2020, the Court denied an appeal of the EPA decision filed by Maryland, except that the Court agreed that EPA did not sufficiently support its rejection based on the cost effectiveness of Maryland's request that two waste coal plants, Cambria Cogeneration (Pa.) and Grant Town Cogen (W.Va.), be required to operate selective noncatalytic reduction (SNCR) controls, and remanded the decision. Maryland v. Wheeler, Case No. 18-1285 (D.C. Cir May 19, 2020).

34 Wisconsin v. EPA, 938 F.3d 303, 318–20 (D.C. Cir. 2019).

35 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA–HQ–OAR–2020–0272; FRL–10013–42– OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).

36 *Id.* at 23066.

37 *Id.* at 23085–23086.

38 *Id.* at 23121.

39 *Id.*

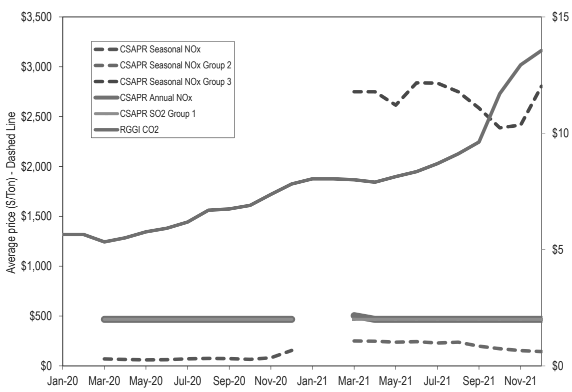
40 On April 30, 2021, the MMU sent a market message to PJM market participants explaining how to account for the changes in cost-based offers. *See* "CSAPR Ozone Season Changes," <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_CSAPR_Ozone_Season_Changes_20210430.pdf>

41 *Id.* at 23123–23124 (Table VII.C.2–1–4).

42 *See* "State Budgets under the Revised Cross-State Air Pollution Rule Update," EPA, <https://www.epa.gov/csapr/state-budgets-under-revised-cross-state-air-pollution-rule-update>.

In 2021, CSAPR annual NO_x prices were 0.8 percent higher on average than in 2020. In 2020, CSAPR Seasonal NO_x prices were on average $77.81 per credit. The CSAPR Seasonal NO_x price for group 2 states averaged $211.05 in 2021, a 171.3 percent increase over the CSAPR Seasonal NO_x price for 2020.[43] The CSAPR Seasonal NO_x price for group 3 states averaged $2,673.23 in 2021, a 3,335.8 percent increase over the CSAPR Seasonal NO_x price for 2020.[44] The components of LMP analysis in Table 3-69 shows that NO_x cost contributed $0.19 to the load-weighted average LMP for 2021. In 2020, the NO_x cost contributed $0.01 to the load-weighted average LMP.

Figure 8-1 Spot monthly average emission price comparison: January 2020 through December 2021



CAA: NSR

Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.[45] NSR requires permits before construction commences. In PJM, permits are issued by state environmental regulators, or in a process involving state and regional EPA regulators.[46]

NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units. The first part considers whether a modification would cause a "significant emission increase" of a regulated NSR pollutant. The second part considers whether any identified increase is also a "significant net emission increase."

On August 1, 2019, the EPA proposed revisions to the NSR permitting program under which, both emissions increases and decreases from a major modification would be considered in the first part of the NSR applicability test.[47] Under the revised rule the need for a permit and associated investments in pollution controls would be more frequently avoided than under the current rule.

On March 25, 2020, the EPA released a memorandum changing the EPA's longstanding interpretation of "begin actual construction" under the NSR preconstruction permitting regulations.[48] [49] EPA policy has been to preclude almost every physical onsite construction activity that is of a permanent nature prior to issuance of a permit. Under the new interpretation, which focuses on the statutory meaning of "emissions unit,"[50] the policy precludes only the construction of the emissions unit. The EPA clarified that the costs and consequences of pre permit construction are risks born by the owner/operators if no permit issues, or issues without the expected terms or conditions. The new interpretation significantly expands the scope of activity that an owner/operator willing to assume the risks may undertake prior to receiving an NSR permit when constructing a project that will include an emissions unit.

CAA: RICE

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power,

43 Tennessee is the only PJM state that remains in the CSAPR NO_x Ozone Season Group 2 Trading Program.
44 Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia participate in the CSAPR NO_x Ozone Season Group 3 Trading Program.
45 42 U.S.C § 7470 et seq.
46 CAA permitting in EPA Region 2 (New Jersey) is the responsibility of the state's environmental regulatory authority; CAA permitting in Region 3 (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) is the shared responsibility of each state's environmental regulatory authority and EPA Region 3; CAA permitting in Region 4 (Kentucky and North Carolina) is the shared responsibility of each state's environmental regulatory authority and EPA Region 4; CAA permitting in EPA Region 5 (Illinois, Indiana, Michigan and Ohio) is the responsibility of each state's environmental regulatory authority.
47 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).
48 See Anne L. Idsal, Principal Deputy Assistant Administrator, Memorandum re Interpretation of "Begin Actual Construction" Under the New Source Review Preconstruction Permitting Regulations" ("March 25th Memo").
49 See 40 CFR § 52.21(b)(11); 40 CFR § 52.21(a)(2)(iii).
50 40 CFR § 52.21(b)(7) ("any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit…").

including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM.

EPA regulations require that RICE that do not meet EPA emissions standards (emergency stationary RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations.[51] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register individually or in portfolios. Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate. The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations.

51 Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf> (Accessed March 2, 2020).

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[52] [53]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[54] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer reviewed.[55] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on Social Cost of Carbon analyses.

Executive Order 13990, Section 6, establishes an Interagency Working Group on the Social Cost of Greenhouse Gases. The group is tasked to develop estimates in the form of monetized damages for the "social cost of carbon" (SCC), the "social cost of nitrous oxide" (SCN), and the "social cost of methane" (SCM), associated with incremental increases in greenhouse gas emissions. The cost estimates would be used by EPA and other agencies to determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses of regulatory and other actions.

Effective October 23, 2015, the EPA placed national limits on the amount of CO_2 that new, modified or reconstructed fossil fuel fired steam power plants would be allowed to emit based on the best system of emission reductions (BSER) determined by the EPA (2015 GHG

52 See CAA § 111.
53 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
54 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (Aug. 8, 2016).
55 *Id.*

NSR Rule).[56] On December 12, 2018, the EPA proposed to revise the 2015 GHG NSR Rule by increasing the allowable emissions and eliminating the requirement for carbon capture for new coal units.[57]

On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan, which ACE had replaced. On February 12, 2021, the EPA issued a memo stating that as a result of the court vacating ACE without reinstating the Clean Power Plan ("CPP"), there are no effective regulations under CAA section 111(d) with respect to greenhouse gas emissions from electric generating units at this time, and states are not currently required to submit plans.[58] The memo also noted: "ongoing changes in electricity generation mean that the emission reduction goals that the CPP set for 2030 have already been achieved."[59]

CWA: WOTUS Definition and Effluents

WOTUS

The Clean Water Act (CWA) applies to navigable waters, which are defined as waters of the United States (WOTUS).[60] [61] The definition of WOTUS is a threshold issue that determines the hydrological scope of the CWA's applicability. Over the past decade, attempts to define WOTUS have been repeatedly addressed by the Courts, and no durable definition has resulted.[62] Establishing a durable definition is important to the electric industry, which needs to plan for compliance with the CWA and related regulations.

October 22, 2019, a new rule that would have defined WOTUS more narrowly was vacated by the U.S. District Court District of Arizona.[63] [64] The new rule was never implemented.

Based on the Court action, the EPA now interprets WOTUS consistent with the pre 2015 regulatory regime. On November 18, 2021, the EPA and the Department the Army announced the signing of a proposed rule to revise the definition of "waters of the United States" to restore the pre-2015 definition of "waters of the United States," updated to reflect consideration of Supreme Court decisions.[65]

The scope of the CWA has expanded as a result of a decision of the U.S. Supreme Court in *County of Maui v. Hawaii Wildlife Fund*, which held that the discharge of pollutants via groundwater requires a CWA permit.[66] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[67] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[68] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[69] Additional litigation or administrative action may clarify the functional discharge analysis.[70] *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[71]

Effluents

The EPA regulates under its National Pollutant Discharge Elimination System (NPDES) permitting authority discharges from and intakes to power plants, including

56 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 90 Fed. Reg. 205 (October 23, 2015) ("2015 GHG NSR Rule"); 40 CFR Part 60, subpart TTTT.

57 *Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, EPA–HQ–OAR–2013–0495; FRL–9987–85– OAR, 83 Fed. Reg. 65424, 65427 (Dec. 20, 2018) ("2018 Proposed Rev. GHG NSR").

58 *See* Joseph Goffman, Acting Assistant Administrator, EPA, Memo re Status of Affordable Clean Energy Rule and Clean Power Plan (February 12, 2021).

59 *Id.*, citing "Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units," EPA-452/R-19-003 (June 2019), at 2-14 to 2-15.

60 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) ("The term "navigable waters" means the waters of the United States, including the territorial seas.").

61 For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."

62 See, e.g., Rapanos v. U.S., 547 U.S. 715 (2006); Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers, 531 U.S. 159 (2001); U.S. v. Riverside Bayview Homes, Inc., 474 U.S. 121 (1985).

63 See *The Navigable Waters Protection Rule: Definition of "Waters of the United States,"* EPA Docket No. EPA–HQ–OW–2018–0149, 85 Fed. Reg. 22250 (April 21, 2020).

64 See Pascua Yaqui Tribe v. U.S. EPA, No. CV-20-00266-TUC-RM, __ F.Supp.3d __ (USDC Ariz. 2021).

65 *See Revised Definition of "Waters of the United States,"* Docket No. EPA–HQ–OW–2021–0602; FRL–6027.4–03– OW, 86 Fed. Reg. 69372 (December 7, 2021); Pasqua Yaqui Tribe v. EPA, Case No. CV-20-00266-TUC-RM, ___ F.Supp.3d ___ (USDC D. Ariz. 2021).

66 Slip. Op. No. 18–260 (April 23, 2020).

67 *Id.*

68 *Id.* at 1.

69 *Id.* at 16 ("The difficulty with this approach, we recognize, is that it does not, on its own, clearly explain how to deal with middle instances. But there are too many potentially relevant factors applicable to factually different cases for this Court now to use more specific language. Consider, for example, just some of the factors that may prove relevant (depending upon the circumstances of a particular case): (1) transit time, (2) distance traveled, (3) the nature of the material through which the pollutant travels, (4) the extent to which the pollutant is diluted or chemically changed as it travels, (5) the amount of pollutant entering the navigable waters relative to the amount of the pollutant that leaves the point source, (6) the manner by or area in which the pollutant enters the navigable waters, (7) the degree to which the pollution (at that point) has maintained its specific identity. Time and distance will be the most important factors in most cases, but not necessarily every case.").

70 *Id.*

71 See *id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").

water cooling systems at steam electric power generating stations, under the CWA.[72]

Executive Order 13990 called for review and improvement of the existing 2020 Steam Electric Reconsideration Rule. The EPA intends to issue a proposed rule in the fall of 2022 to strengthen certain discharge limits applicable to steam generating units.[73]

The EPA is currently implementing its 2015 and 2020 rules.[74] [75] The 2015 Rule established limitations and standards applicable to discharges from steam electric generating units from bottom ash (BA) transport water, flue gas desulfurization (FGD) wastewater, fly ash (FA) transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non chemical metal cleaning wastes. The 2020 Rule revised the limitations and standards for BA transport water and FGD wastewater, leaving the other limitations and standards in place. The 2020 Rule applied less stringent effluent limits to three new subcategories of units: High FGD flow plants, low utilization generating units, and generating units that will permanently cease the combustion of coal by 2028.

Units subject to the generally applicable limits had to comply with the 2020 Rule as soon as possible on or after October 13, 2021, but no later than December 31, 2025.[76] Some owners have already indicated an intent to close generating units based on the discharge limits in the 2020 Rule.

The EPA is now implementing its Effluent Guidelines. The EPA has also proposed to tighten those guidelines.[77] The Effluent Guidelines establish effluent limitations and pretreatment standards applicable to steam electric generating units. Plants are required to inform regulators of their plans to comply with the new rule by upgrading their plants with pollution control equipment or retiring their units by 2028.[78]

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[79] Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

In April 2015, the EPA issued a rule under RCRA, the Coal Combustion Residuals rule (2015 CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[80] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that EPA determines that they are ''at least as protective as'' the EPA CCR regulations.[81]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[82]

The 2018 CCRR Revisions provide for two types of alternative performance standards. The first type of standards allows a state director (if a state has EPA approved CCR permit program) or the EPA (if no state program) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and during post closure care. The second type allows

72 See 40 CFR Part 423. For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."
73 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021).
74 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA–HQ–OW–2009–0819; FRL–9930–48– OW, 80 Fed. Reg. 67838 (November 3, 2015).
75 See *Steam Electric Reconsideration Rule*, Docket No. EPA–HQ–OW–2009–0819; FRL–10014–41–OW, 85 Fed. Reg. 64650 (October 13, 2020).
76 *Id.* at 64652.
77 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021); Steam Electric Reconsideration Rule, Docket No. EPA–HQ–OW–2009–0819; FRL–10014–41–OW, 85 Fed. Reg. 64650 (October 13, 2020); *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA–HQ–OW–2009–0819; FRL–9930–48– OW, 80 Fed. Reg. 67838 (November 3, 2015) (collectively "Effluent Guidelines").
78 85 Fed. Reg. 64650, 64679–82.
79 42 U.S.C. §§ 6901 *et seq.*
80 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).
81 The Water Infrastructure Improvements for the Nation Act (WIIN Act).
82 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA–HQ–OLEM–2017–0286, 83 Fed. Reg. 36435 (July 30, 2018).

issuance of technical certifications by a state director in lieu of a professional engineer.

The 2018 CCRR Revisions revised the groundwater protection standards for health-based levels for four contaminants: cobalt at 6 mg/L; lithium at 40 mg/L; molybdenum at 100 mg/L and lead at 15 mg/L. Standards for other monitored contaminants follow the Maximum Contaminant Level (MCL) established under the Safe Water Drinking Act.

The 2018 CCRR Revisions extended the deadline for closing coal ash units in two situations: (i) detection of a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or (ii) inability to comply with the location restriction regarding placement above the uppermost aquifer. The exceptions in the 2018 CCRR to the standards in the 2015 CCRR and relaxation of the deadlines create a less stringent federal rule.

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.[83] On July 29, 2020, the EPA finalized revisions to CCRR in compliance with the court orders ("Revised CCRR").[84] The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.[85] Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be "technically feasibly implemented."[86] Utilities had until November 30, 2020, to obtain an automatic extension upon certification of need for additional time.[87] [88] Upon receipt of required documentation satisfying certain criteria, the EPA could grant certain extensions, including to as late as October 17, 2028, for a facility with a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.[89]

The EPA has under review 16 completed applications from PJM plants for extensions of the deadline for compliance with the Revised CCRR. The EPA has proposed action on three applications.

The EPA has proposed to deny two applications affecting PJM power stations: The General James M. Gavin Plant (2,600 MW) owned by Lightstone Generation LLC, a 50-50 joint venture of funds managed by ArcLight Capital Partners and Blackstone Group, Inc., and is located in Cheshire, Ohio (Gavin);[90] and the Clifty Creek Power Plant (1,300 MW) owned by Ohio Valley Electric Corp. (OVEC) and located in Madison, Indiana (Clifty Creek).[91] The comment period for the proposed denial for both plants ends February 23, 2022. The EPA proposes that both Gavin and Clifty Creek cease receipt of waste and initiate closure of its surface impoundment no later than 135 days from the date of the EPA's final decision.[92] The EPA provides the potential for an extension for such period that PJM may determine that Gavin or Clifty Creek is needed for reliability and the EPA agrees is appropriate.[93]

The EPA proposed to approve East Kentucky Power Cooperative's request to extend its deadline to discontinue use of an unlined ash pond to November 30, 2022, for its H.L. Spurlock Plant (1,350 MW) in Maysville, Kentucky.[94] The proposed extension is on condition that groundwater monitoring issues are addressed.[95] In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in non participating states, noticed February 20, 2020.[96] This proposal includes requirements for federal CCR permit applications, content and modification, as well as procedural requirements. The EPA would implement this permit program at CCR units located in states that have not submitted their own CCR permit program for

83 Utility Solid Waste Activities Group, et al. v. EPA, No. 15-1219 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. March 13, 2019).
84 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure*, EPA-HQ-OLEM-2019-0172; FRL-10002- 02-OLEM, 85 Fed. Reg. 53516 (August 28, 2020).
85 *Id.* at 53516-53517, 53536.
86 *Id.* at 53546; 40 CFR § 257.103(f)(1).
87 *Id.* at 65942.
88 A number of plants in PJM timely filed for extensions.
89 *Id.*
90 Proposed Denial of Alternative Closure Deadline for General James M. Gavin Plant, Proposed Decision, Docket No.: EPA-HQ-OLEM-2021-0590 (January 11, 2022) ("Gavin Proposed Denial Order").
91 Proposed Denial of Alternative Closure Deadline for Clifty Creek Power Station, Proposed Decision, Docket No. EPA-HQ-OLEM-2021-0587(January 11, 2022) ("Clifty Creek Proposed Denial Order").
92 Gavin Proposed Denial Order at 88; Clifty Creek Proposed Denial Order at 77.
93 Gavin Proposed Denial Order at 86; Clifty Creek Proposed Denial Order at 76-77.
94 Conditional Approval of an Alternative Closure Deadline for H.L. Spurlock Power Station, Maysville, Kentucky, Proposed Decision, Docket No. EPA-HQ-OLEM-2021-0595 (January 11, 2022) at 32.
95 *Id.* at 48-62.
96 *See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities*; Federal CCR Permit Program, 85 Fed. Reg. 9940 (Feb. 20, 2020).

approval. No PJM state has yet applied for EPA approval of a coal ash permitting program.

In Virginia, the Waste Management Board amended the Virginia Solid Waste Management Regulations in December 2015, to incorporate the EPA's 2015 CCRR, and did not adopt the less stringent 2018 CCRR Revisions.[97] In 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[98] Effective July 1, 2019, coal ash ponds at power stations in the Chesapeake Bay Watershed had to be closed by removal of coal ash. The removed coal ash either had to be recycled (at least 6.8 million cubic yards) or disposed of in a modern, lined landfill. The Virginia DEQ is addressing closing ash ponds under two types of environmental permits: wastewater discharge permits covering the removal of treated water from the ponds; or solid waste permits covering the permanent closure of the ponds.

On March 30, 2020, in response to a statutory mandate,[99] the Illinois Environmental Protection Agency (Illinois EPA) proposed rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[100] The proposed rules contain standards for the storage and disposal of coal combustion residuals in surface impoundments. The proposed rules include a permitting program and are intended to meet federal standards.[101] Presumably the rules, once finalized, would be the basis for an application under RCRA allowing the Illinois EPA to also administer the federal regulatory program. The Illinois EPA has identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.[102] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[103]

The North Carolina Department of Environmental Quality (NCDEQ) has initiated a rule making on rules for the disposal or recycling of coal combustion residuals. None of the affected power stations or power station impoundments are located in the PJM Dominion Zone (which includes a portion of northeast coastal North Carolina).

The Maryland Department of Environment (MDE) indicated in April 2020, that it would require GenOn Holdings Inc. to meet a November 1, 2020, deadline for compliance with effluent guidelines at Chalk Point Generating Station, Dickerson Generating Station and Morgantown Generating Station.[104] On May 15, 2020, GenOn announced its decision to retire the Dickerson Generating Station.[105] Dickerson Generating Station was retired effective August 13, 2020. The Chalk Point coal units were retired effective June 1, 2021. On June 9, 2021, GenOn reported that it would retire its Morgantown coal fired unit by May 31, 2022, five years earlier than previously announced.[106]

State Environmental Regulation

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[107]

- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, Illinois Governor J.B. Pritzker signed the Climate and Equitable Jobs Act (CEJA). CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on

97 The following Virginia power stations host coal ash ponds: Bremo Power Station, Chesapeake Energy Center, Chesterfield Power Station, Clinch River Plant and Possum Point Power Station, owned by Dominion Energy; and Glen Lyn Plant, owned by Appalachian Power.
98 Va. Code § 10.1-1402.03.
99 Ill. Public Act 101-171 (a.k.a. SB 09).
100 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.
101 See *In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments*, No. R 2020-019 (March 30, 2020) at 1 (Proposed New 35 Ill. Adm. Code 845) ("Proposed Illinois CCR Rules").
102 Proposed Illinois Rules at 3.
103 *Id.* at 3.
104 See Potomac Riverkeeper Network, Press Release, "Maryland Proposes to Reject Effort to Delay Pollution Reductions," (Posted April 4, 2020), <https://www.potomacriverkeepernetwork.org/maryland-proposes-to-reject-effort-to-delay-pollution-reductions/>.
105 See "GenOn Holdings, Inc. Announces Retirement of Dickerson Coal Plant," (May 15, 2020) <https://www.genon.com/genon-news/genon-holdings-inc-announces-retirement-of-dickerson-coal-plant>.
106 See "GenOn Holdings, LLC Announces Retirement of Three Coal-Fired Power Plants," (June 9, 2021) <https://www.genon.com/genon-news/genon-holdings-llc-announces-retirement-of-three-coal-fired-power-plants>.
107 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix H: "Environmental and Renewable Energy Regulations."

a rolling 12 month basis going forward.[108] [109] New investor owned, gas-fired units will have emissions caps after three years. The emissions caps are based on average emissions over a three year period from 2018 through 2020. The capped emissions are CO2e and co-pollutants.[110] [111] The resultant emissions caps are very low for some units and much higher for others. More than 10,000 MW of capacity is currently affected, about half of which have requested that the MMU calculate a unit specific opportunity cost. The MMU is calculating opportunity costs for units that make request and provide required data.

- **New Jersey HEDD.** Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules. New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

State Regulation of Greenhouse Gas Emissions

Some states have enacted legislation and participated in multistate programs designed to reduce or eliminate greenhouse gas emissions.

CEJA

In addition to the provisions creating nuclear subsidies, mandating closure of fossil fuel generation by 2045, and limiting emissions from natural gas fired resources the CEJA includes provisions promoting the development of batteries and utility scale solar at the sites of up to five closed coal plants, two of which may be located in PJM. CEJA grants a subsidy of $110,000/MW for battery projects with at least 37 MW of capacity, capped at $28 million per year. A solar resource at a defined site may select to receive either the battery subsidies or to sell premium RECs for $30 each.

Clean Energy Standards

In April 2020, Virginia enacted the Virginia Clean Economy Act, which orders the closure of most coal generation in state by 2024, most fossil fuel generation by 2045, and adopts a 100 percent clean energy standard by 2045.[112] The legislation mandates Chesterfield Power Station Units 5 & 6 and Yorktown Power Station Unit 3 to be retired by the end of 2024, Altavista, Southampton and Hopewell to be retired by the end of 2028 and Virginia Power's remaining fossil fuel units to be retired by the end of 2045, unless the retirement of such generating units will compromise grid reliability or security.[113] The legislation also imposes a temporary moratorium on Certificates of Public Convenience and Necessity for fossil fuel generation, unless the resources are needed for grid reliability.[114]

108 Letter of John J. Kim, Director, Illinois Environmental Protection Agency, to Dr. Joseph Bowring, Market Monitor (January 21, 2022) ("IEPA January 21st Letter") <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IL_EPA_CEJA_Response_to_the_IMM_20220121.pdf>.

109 The IEPA January 21st Letter explains: "All of this information is already reported to USEPA by sources subject to Section k-5, per 40 CFR Part 98, and Illinois does not intend for any changes in existing methodologies in that regard. Specifically, Part 98.2(a)(1) requires Part 98 reporting of sources that are subject to Part 75. CO2e emissions are calculated using Equation A-1 from 40 CFR 98.2(b)(4), and emissions data for specific contributing pollutants are taken from a combination of CEMS data and other measurement or estimation methods. Part 98.3 requires reporting of CO2, CH4, N2O, and each fluorinated GHG. This covers all pollutants used to calculate CO2e that would be emitted by sources subject to Section k-5. Part 75.13 requires use of CO2 CEMS or alternate methods that are acceptable continuous monitoring methods detailed in Appendices F and G to Part 75. Part 98 Tables C-1 and C-2 have default values for CH4, N2O, and other GHGs, based on fuel type, that sources should continue to use for requirements pursuant to Section k-5; they are essentially considered to be continuous parameter monitoring based on fuel consumption."

110 Carbon dioxide equivalent (CO2e) emissions means the total emissions of six greenhouse gases (carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride). Co-pollutants mean the six criteria pollutants identified by the US EPA pursuant to the Clean Air Act: Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particle Pollution, and Sulfur Dioxide.

111 See Energy Transition Act, Public Act 102-0662, Section 90-55, which amends section 9.15 (k-5) FOR the Illinois Environmental Protection Act.

112 Va. HB 1526/SB 851.

113 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).

114 *Id.*

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, Vermont and Virginia (as of January 1, 2021) to cap CO_2 emissions from power generation facilities.[115]

Delaware, Maryland, New Jersey and Virginia are the only PJM states that are members of RGGI. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[116] Virginia joined RGGI on January 1, 2021.

Pennsylvania planned to join RGGI on January 1, 2022 but has not done so due to a resolution that passed the Pennsylvania legislature. Pennsylvania Governor Tom Wolf issued an executive order on October 3, 2019, directing the Pennsylvania Department of Environmental Protection (DEP) to develop a proposal to limit carbon emissions from fossil fuel generators that is consistent with RGGI.[117] The Pennsylvania Environmental Quality Board (EQB), on September 15, 2020, approved a draft regulation developed by the DEP that governs Pennsylvania's entry into RGGI in 2022.[118] The DEP announced on September 1, 2021, that the Independent Regulatory Review Commission approved the regulation for RGGI participation beginning January 1, 2022.[119] The Pennsylvania state senate passed a resolution 32–18 on October 27, 2021, disapproving Pennsylvania's RGGI rule.[120] The Pennsylvania house passed the resolution 130–70 on December 15, 2021. Governor Wolf vetoed the resolution on January 10, 2022. The Pennsylvania legislature is now attempting to override the Governor's veto, but this looks unlikely based on the recent votes that fall short of the two thirds override margin.[121] If enacted, the CO_2 Budget Trading Program is likely to be challenged in court.

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities, in short tons and metric tonnes, for the 3rd control period, the 4th control period, and the first four auctions of the 5th control period.[122] [123] The clearing price for the auction held December 1, 2021 was $13.00 per allowance (equal to one short ton of CO_2) which is the Cost Containment Reserve (CCR) trigger price.[124] The CCR trigger price serves as price cap and bids are not cleared above the CCR trigger price. As shown in Table 8-2, the initial supply of allowances representing 23,121,518 short tons was not sufficient to meet the demand at the $13.00 CCR trigger price. The additional demand in excess of the CRR trigger price was met with 3,919,482 CCR allowances.[125] The December auction clearing price increased 39.8 percent over the last auction clearing price of $9.30 in September 2021.

115 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.

116 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.

117 Executive Order No. 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor (Oct. 3, 2019), <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

118 "Environmental Quality Board Approves Proposed Climate Change Regulation," DEP Newsroom, (September 15, 2020) <https://www.ahs.dep.pa.gov/NewsRoomPublic/articleviewer.aspx?id=21865&typeid=1>.

119 "Independent Regulatory Review Commission Approves CO2 Budget Final Rulemaking," DEP Newsroom (September 1, 2021) <https://www.ahs.dep.pa.gov/NewsRoomPublic/articleviewer.aspx?id=21997&typeid=1>.

120 "Senate moves to block key part of Wolf's climate plan," McDevitt, Rachael, StateImpact Pennsylvania <https://stateimpact.npr.org/pennsylvania/2021/10/27/senate-moves-to-block-key-part-of-wolfs-climate-plan/>.

121 Governor Wolf successfully vetoed Pa. H.B. 2025 proposed in 2020, which would have restricted the Governor's authority to join RGGI.

122 Each control period is three years in duration. The 3rd control period covers 2015 through 2017. The 4th control period covers 2018 through 2020. The 5th control period covers 2021 through 2023.

123 The September 3, 2015, auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $6.00 per ton in 2015. The auctions on March 5, 2014, and September 3, 2015, were the only auctions to use CRRs.

124 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

125 "CO_2 Allowances Sold for $13.00 in 54th RGGI Auction", RGGI New Release, RGGI Inc. (December 3, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

Table 8-2 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th and 5th Control Periods[126]

	Short Tons				Metric Tonnes			
Auction Date	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold
March 11, 2015	$5.41	15,272,670		15,272,670	$5.96	13,855,137		13,855,137
June 3, 2015	$5.50	15,507,571		15,507,571	$6.06	14,068,236		14,068,236
September 9, 2015	$6.02	15,374,294	10,000,000	25,374,294	$6.64	13,947,329	9,071,850	23,019,179
December 2, 2015	$7.50	15,374,274		15,374,274	$8.27	13,947,311		13,947,311
March 9, 2016	$5.25	14,838,732		14,838,732	$5.79	13,461,475		13,461,475
June 1, 2016	$4.53	15,089,652		15,089,652	$4.99	13,689,106		13,689,106
September 7, 2016	$4.54	14,911,315		14,911,315	$5.00	13,527,321		13,527,321
December 7, 2016	$3.55	14,791,315		14,791,315	$3.91	13,418,459		13,418,459
March 8, 2017	$3.00	14,371,300		14,371,300	$3.31	13,037,428		13,037,428
June 7, 2017	$2.53	14,597,470		14,597,470	$2.79	13,242,606		13,242,606
September 8, 2017	$4.35	14,371,585		14,371,585	$4.80	13,037,686		13,037,686
December 8, 2017	$3.80	14,687,989		14,687,989	$4.19	13,324,723		13,324,723
March 14, 2018	$3.79	13,553,767		13,553,767	$4.18	12,295,774		12,295,774
June 13, 2018	$4.02	13,771,025		13,771,025	$4.43	12,492,867		12,492,867
September 9, 2018	$4.50	13,590,107		13,590,107	$4.96	12,328,741		12,328,741
December 5, 2018	$5.35	13,360,649		13,360,649	$5.90	12,120,580		12,120,580
March 13, 2019	$5.27	12,883,436		12,883,436	$5.81	11,687,660		11,687,660
June 5, 2019	$5.62	13,221,453		13,221,453	$6.19	11,994,304		11,994,304
September 4, 2019	$5.20	13,116,447		13,116,447	$5.73	11,899,044		11,899,044
December 4, 2019	$5.61	13,116,444		13,116,444	$6.18	11,899,041		11,899,041
March 11, 2020	$5.65	16,208,347		16,208,347	$6.23	14,703,969		14,703,969
June 3, 2020	$5.75	16,336,298		16,336,298	$6.34	14,820,045		14,820,045
September 2, 2020	$6.82	16,192,785		16,192,785	$7.52	14,689,852		14,689,852
December 2, 2020	$7.41	16,237,495		16,237,495	$8.17	14,730,412		14,730,412
March 3, 2021	$7.60	23,467,261		23,467,261	$8.38	21,289,147		21,289,147
June 2, 2021	$7.97	22,987,719		22,987,719	$8.79	20,854,114		20,854,114
September 8, 2021	$9.30	22,911,423		22,911,423	$10.25	20,784,899		20,784,899
December 1, 2021	$13.00	23,121,518	3,919,482	27,041,000	$14.33	20,975,494	3,555,695	24,531,190

The RGGI auction held on December 1, 2021, generated 351.5 million in auction revenue. RGGI auctions have generated $4.7 billion in auction revenue since 2008.[127] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2019 reporting year, have spent approximately 54 percent of the revenue on energy efficiency, 14 percent on clean and renewable energy, 10 percent on greenhouse gas abatement and 15 percent on direct bill assistance.[128]

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on 2021 CO_2 emission levels and the RGGI clearing price for the December 2021 auction ranges from $1.9 billion per year to $3.7 billion per year depending on associated reductions in carbon emission levels (Table 8-3).[129] Table 8-3 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2021 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-3 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2021 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[130]

126 See Regional Greenhouse Gas Initiative, "Auction Results," <https://www.rggi.org/auctions/auction-results> (Accessed January 27, 2021).
127 See Auction Results at <https://www.rggi.org/>.
128 *The Investment of RGGI Proceeds in 2019*, The Regional Greenhouse Gas Initiative (RGGI), June 2021, <https://www.rggi.org/investments/proceeds-investments>.
129 This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.
130 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/20190617a.shtml>.

Table 8-3 Estimated CO_2 allowance revenue at December 2021 RGGI price level[131 132]

		Estimated CO_2 allowance revenue ($ millions), carbon price $13.00 per short ton					
Jurisdiction	2021 power generation CO_2 emissions (short tons)	5 percent reduction below 2020 emission levels	10 percent reduction below 2020 emission levels	15 percent reduction below 2020 emission levels	20 percent reduction below 2020 emission levels	25 percent reduction below 2020 emission levels	50 percent reduction below 2020 emission levels
Delaware	1,569,515.5	$19.4	$18.4	$17.3	$16.3	$15.3	$10.2
Illinois	20,545,590.8	$253.7	$240.4	$227.0	$213.7	$200.3	$133.5
Indiana	27,066,021.8	$334.3	$316.7	$299.1	$281.5	$263.9	$175.9
Kentucky	23,972,416.9	$296.1	$280.5	$264.9	$249.3	$233.7	$155.8
Maryland	10,527,468.1	$130.0	$123.2	$116.3	$109.5	$102.6	$68.4
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	8,424,107.9	$104.0	$98.6	$93.1	$87.6	$82.1	$54.8
North Carolina	61,960.5	$0.8	$0.7	$0.7	$0.6	$0.6	$0.4
Ohio	62,670,551.1	$774.0	$733.2	$692.5	$651.8	$611.0	$407.4
Pennsylvania	67,579,691.3	$834.6	$790.7	$746.8	$702.8	$658.9	$439.3
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	22,491,149.9	$277.8	$263.1	$248.5	$233.9	$219.3	$146.2
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	51,728,460.2	$638.8	$605.2	$571.6	$538.0	$504.4	$336.2
Total	296,636,934.0	$3,663.5	$3,470.7	$3,277.8	$3,085.0	$2,892.2	$1,928.1

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-4 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. The 2021 compliance year is the first year of the fifth control period.

In 2021, RGGI announced a third adjustment to the RGGI emissions cap to account for banked allowances from previous control periods.[133 134] The first adjustment removed 57.5 million allowances that were banked or unused from the first control period. The reduction to the RGGI emissions cap was spread over a seven year period beginning in 2014 and ending with 2020.[135] A second cap adjustment, corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13.7 million allowances per year and was in place through 2020.[136] The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.[137] The base emissions cap for each of the next five years will be reduced by 19.1 allowances. The percent change columns in Table 8-4 show the year to year percent changes in the base RGGI cap and the adjusted RGGI cap.[138] The adjusted emissions cap for 2021 marks the first year the adjusted carbon emissions cap has increased since the start of RGGI.[139] Figure 8-2 shows the adjusted carbon budgets for the RGGI states. All states, with the exception of New Jersey, have a higher 2021 adjusted carbon budget relative to the corresponding 2020 budget. The RGGI clearing price since 2014 has been on average 142.4 percent higher than the prices prior to the emission cap adjustments.

131 The 2020 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.

132 Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-3 do not reflect offset allowances.

133 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

134 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

135 "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014) at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.

136 Id.

137 "Third Adjustment for Banked Allowances Announcement", Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

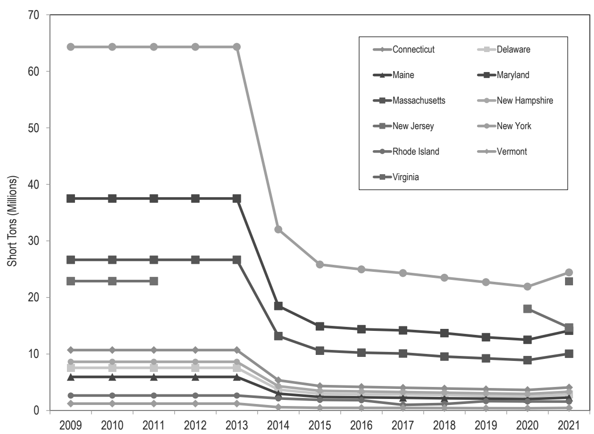
138 Percent changes for years with membership changes do not reflect the impacts of the change in membership. For example, the percent changes from 2019 to 2020 do not reflect the impact of New Jersey rejoining RGGI.

139 The increase of 4.5 percent does not reflect the addition of Virginia as a RGGI state.

Table 8-4 RGGI emissions cap history[140 141 142]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009		$2.77	188,076,976		188,076,976	
2010	1st	$1.93	188,076,976	0.0%	188,076,976	0.0%
2011		$1.89	188,076,976	0.0%	188,076,976	0.0%
2012		$1.93	165,184,246	0.0%	165,184,246	0.0%
2013	2nd	$2.92	165,184,246	0.0%	165,184,246	0.0%
2014		$4.72	91,000,000	(44.9%)	82,792,336	(49.9%)
2015		$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016	3rd	$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018		$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019	4th	$5.43	80,363,945	(2.3%)	58,472,538	(3.1%)
2020		$6.41	96,354,847	(2.5%)	74,463,439	(3.4%)
2021		$9.61	119,767,784	(3.9%)	100,677,454	4.5%
2022	5th		116,112,784	(3.1%)	97,022,454	(3.6%)
2023			112,457,784	(3.1%)	93,367,454	(3.8%)

Figure 8-2 RGGI adjusted carbon budgets by state[143]



140 See Regional Greenhouse Gas Initiative, "Allowance Distribution," <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed April 13, 2021).
141 RGGI budgets for 2022 and 2023 are found in a RGGI press release, "Third Adjustment for Banked Allowances Announcement," March 15, 2021 <https://www.rggi.org/news-releases/rggi-releases>.
142 The increase in the RGGI Cap and the RGGI Adjusted Cap in 2020 is due to the reentry of New Jersey. The new cap is 18 million short tons higher than the previously published 2020 caps.
143 Data for the figure was collected from allowance distribution reports available on the RGGI website <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed April 13, 2021).

If higher carbon prices were implemented in PJM, the associated revenues flowing to states would also increase. Table 8-5 shows the estimated allowance revenue for PJM states for carbon prices ranging from $10 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. Allowance revenues to states would be $1.5 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2020.

Table 8-5 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
	5 percent reduction below 2020 emission levels	10 percent reduction below 2020 emission levels	15 percent reduction below 2020 emission levels	20 percent reduction below 2020 emission levels	25 percent reduction below 2020 emission levels	50 percent reduction below 2020 emission levels
Jurisdiction		Carbon Price ($ per short ton)			$10.00	
Delaware	$14.9	$14.1	$13.3	$12.6	$11.8	$7.8
Illinois	$195.2	$184.9	$174.6	$164.4	$154.1	$102.7
Indiana	$257.1	$243.6	$230.1	$216.5	$203.0	$135.3
Kentucky	$227.7	$215.8	$203.8	$191.8	$179.8	$119.9
Maryland	$100.0	$94.7	$89.5	$84.2	$79.0	$52.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$80.0	$75.8	$71.6	$67.4	$63.2	$42.1
North Carolina	$0.6	$0.6	$0.5	$0.5	$0.5	$0.3
Ohio	$595.4	$564.0	$532.7	$501.4	$470.0	$313.4
Pennsylvania	$642.0	$608.2	$574.4	$540.6	$506.8	$337.9
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$213.7	$202.4	$191.2	$179.9	$168.7	$112.5
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$491.4	$465.6	$439.7	$413.8	$388.0	$258.6
Total	$2,818.1	$2,669.7	$2,521.4	$2,373.1	$2,224.8	$1,483.2
		Carbon Price ($ per short ton)			$25.00	
Delaware	$37.3	$35.3	$33.4	$31.4	$29.4	$19.6
Illinois	$488.0	$462.3	$436.6	$410.9	$385.2	$256.8
Indiana	$642.8	$609.0	$575.2	$541.3	$507.5	$338.3
Kentucky	$569.3	$539.4	$509.4	$479.4	$449.5	$299.7
Maryland	$250.0	$236.9	$223.7	$210.5	$197.4	$131.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$200.1	$189.5	$179.0	$168.5	$158.0	$105.3
North Carolina	$1.5	$1.4	$1.3	$1.2	$1.2	$0.8
Ohio	$1,488.4	$1,410.1	$1,331.7	$1,253.4	$1,175.1	$783.4
Pennsylvania	$1,605.0	$1,520.5	$1,436.1	$1,351.6	$1,267.1	$844.7
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$534.2	$506.1	$477.9	$449.8	$421.7	$281.1
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,228.6	$1,163.9	$1,099.2	$1,034.6	$969.9	$646.6
Total	$7,045.1	$6,674.3	$6,303.5	$5,932.7	$5,561.9	$3,708.0
		Carbon Price ($ per short ton)			$50.00	
Delaware	$74.6	$70.6	$66.7	$62.8	$58.9	$39.2
Illinois	$975.9	$924.6	$873.2	$821.8	$770.5	$513.6
Indiana	$1,285.6	$1,218.0	$1,150.3	$1,082.6	$1,015.0	$676.7
Kentucky	$1,138.7	$1,078.8	$1,018.8	$958.9	$899.0	$599.3
Maryland	$500.1	$473.7	$447.4	$421.1	$394.8	$263.2
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$400.1	$379.1	$358.0	$337.0	$315.9	$210.6
North Carolina	$2.9	$2.8	$2.6	$2.5	$2.3	$1.5
Ohio	$2,976.9	$2,820.2	$2,663.5	$2,506.8	$2,350.1	$1,566.8
Pennsylvania	$3,210.0	$3,041.1	$2,872.1	$2,703.2	$2,534.2	$1,689.5
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,068.3	$1,012.1	$955.9	$899.6	$843.4	$562.3
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,457.1	$2,327.8	$2,198.5	$2,069.1	$1,939.8	$1,293.2
Total	$14,090.3	$13,348.7	$12,607.1	$11,865.5	$11,123.9	$7,415.9

Table 8-6 shows the estimated impact of five different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $10.00 per tonne, the PJM load-weighted average LMP in 2021 would have increased by 4.2 percent.[144]

Table 8-6 Estimated impact of carbon price on LMP: 2020 and 2021

		2020			2021		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$21.77	$23.32	7.1%	$39.78	$39.91	0.3%
Scenario 2	$10.00	$21.77	$25.08	15.2%	$39.78	$41.48	4.2%
Scenario 3	$15.00	$21.77	$26.85	23.3%	$39.78	$43.04	8.2%
Scenario 4	$25.00	$21.77	$30.37	39.5%	$39.78	$46.17	16.0%
Scenario 5	$50.00	$21.77	$39.17	79.9%	$39.78	$53.99	35.7%

Table 8-7 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[145] [146] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.52 per MWh for a new combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

Table 8-7 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.45	$4.90	$7.36	$24.52	$49.04	$98.08	$196.17
CC	$1.67	$3.34	$5.01	$16.71	$33.41	$66.83	$133.65
CP	$4.32	$8.63	$12.95	$43.15	$86.30	$172.60	$345.21

Table 8-7 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $193.07 per credit in 2021. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. If the MWh produced by the solar resource resulted in avoiding the production of a MWh from a CT, the value of carbon reduction implied by the SREC price is a carbon price slightly less than $400 per tonne. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50.00 per tonne, assuming that a MWh from a CT is avoided, is $24.52 per MWh.

Applying this method to Tier I and Class I REC and SREC price histories yields the implied carbon prices in Table 8-8. The carbon price implied by the average REC price during 2021 in Washington, DC is $11.33 per tonne which is $3.00 per tonne lower than the December 1, 2021 RGGI clearing price of $14.33 per tonne. All other carbon prices implied by renewable RECs are well above the RGGI clearing price, and well below the social cost of carbon which is estimated to be in the range of $50 per tonne.[147] The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The carbon prices implied by the SREC prices all exceed the carbon prices implied by the corresponding REC prices, and all exceed the social cost of carbon.

144 LMPs are recalculated to account for the defined cost of carbon emissions on marginal units' offer prices. The LMP calculation is not based on a counterfactual redispatch of the system to determine the marginal units and the marginal costs that would have occurred if all units had made all offers at short run marginal cost. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

145 Heat rates from: *2021 State of the Market Report for PJM: January through June*, Section 7: Net Revenue, Table 7-3.

146 Carbon emissions rates from: Table A.3. Carbon Dioxide Uncontrolled Emission Factors, Energy Information Administration, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed March 9, 2020).

147 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

Table 8-8 Implied carbon price based on REC and SREC prices: 2009 through 2021[148]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jurisdiction with Tier I or Class I REC	**Carbon Price ($ per tonne) Implied by REC Prices**												
Delaware					$34.15	$35.17	$26.25	$23.57	$10.26	$11.57	$16.05	$19.88	
Maryland	$2.07	$1.92	$3.06	$6.34	$17.46	$28.45	$29.18	$26.09	$23.12	$21.28	$17.76	$19.92	$20.48
New Jersey	$13.34	$17.74	$8.58	$4.74	$13.09	$21.04	$25.29	$26.93	$24.01	$22.01	$19.19	$20.48	$20.42
Ohio						$10.16	$5.89	$4.02	$6.27	$11.17	$14.00	$16.28	$18.54
Pennsylvania	$6.82	$8.13	$3.33	$4.29	$15.87	$26.66	$28.88	$26.35	$23.35	$21.47	$17.91	$20.00	$20.07
Washington, D.C.							$3.19	$4.04	$4.88	$4.68	$5.50	$8.67	$11.33
Jurisdiction with Solar REC	**Carbon Price ($ per tonne) Implied by Solar REC Prices**												
Delaware						$117.25	$85.40	$86.48	$35.70	$17.33			
Maryland		$546.11	$494.54	$382.57	$304.54	$292.70	$251.23	$183.09	$127.67	$87.00	$83.93	$101.37	$116.86
New Jersey	$1,372.37	$1,352.15	$1,309.00	$537.08	$345.94	$326.21	$388.73	$424.21	$459.21	$445.00	$409.08	$392.99	$393.68
Ohio						$82.32	$45.12	$36.15	$31.82	$21.67	$26.57		
Pennsylvania	$610.05	$590.57	$378.67	$101.80	$68.34	$75.90	$66.89	$55.06	$43.84	$28.07	$51.50	$63.61	$69.30
Washington, D.C.	$712.98	$436.28	$501.62	$655.52	$956.55	$957.46	$994.05	$993.49	$866.17	$840.35	$848.82	$866.79	$867.85
Regional Greenhouse Gas Initiative	**CO_2 Allowance Price ($ per tonne)**												
RGGI clearing price	$3.06	$2.12	$2.08	$2.13	$3.22	$5.21	$6.72	$4.93	$3.77	$4.86	$5.98	$7.06	$10.59

State Renewable Portfolio Standards

Ten of 14 PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called eligible technologies. Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS must pay penalties (alternative compliance payments).

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[149] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of December 31, 2021, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of December 31, 2021, Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties.[150] Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[151]

As of December 31, 2021, Kentucky, Tennessee and West Virginia had no renewable portfolio standards.

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information

148 There were no trades in 2018 and 2019 for Ohio SRECs available in the Evolution Markets, Inc. data.
149 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 23, 2019).
150 Effective January 1, 2021 the Virginia voluntary RPS is being replaced with a mandatory RPS.
151 See the Indiana Utility Regulatory Commission's "2021 Annual Report," at 37 (Oct. 2021) <https://www.in.gov/iurc/2981.htm>.

with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[152]

Table 8-9 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year.

Table 8-9 Renewable and alternative energy standards of PJM jurisdictions: 2021 to 2030[153 154]

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	21.00%	22.00%	23.00%	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%
Illinois	19.00%	20.50%	22.00%	23.50%	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%
Maryland	33.30%	32.60%	34.40%	36.20%	38.00%	40.50%	44.00%	45.50%	50.00%	52.50%
Michigan	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	23.50%	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%
North Carolina	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)	6.00%	7.00%	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%
Virginia (Phase II utilities)	14.00%	17.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%
Washington, D.C.	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%
Jurisdiction with Voluntary Standard										
Indiana	7.00%	7.00%	7.00%	7.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jurisdiction with No Standard										
Kentucky	No Renewable Portfolio Standard									
Tennessee	No Renewable Portfolio Standard									
West Virginia	No Renewable Portfolio Standard									

The Climate and Equitable Jobs Act (CEJA), which became effective on September 15, 2021 in Illinois, increased the RPS target percent from 25 percent by 2025 to 40 percent by 2030. CEJA also increased the quotas for RECs sourced from new wind and new photovoltaic resources, and made changes to eligible technologies and geographic restrictions. See Table 8-10 for details.

Updates to the Maryland RPS became effective on June 1, 2021. Maryland Senate Bill 65 changed the intermediate RPS target levels while maintaining the target of 50.0 percent renewable by 2030.[155] Part of the legislation was to eliminate resources fueled by black liquor as a Tier 1 eligible technology. Senate Bill 65 reduced the penalty for solar non compliance from $100 per credit to $80 per credit, and extended the Tier 2 standard which was scheduled to expire with the 2020 compliance year.

The Delaware General Assembly passed new RPS legislation on February 10, 2021. The new law updates the Delaware RPS targets from 25 percent in 2025 to 40 percent in 2035.[156] Additional details are provided in Table 8-10.

On April 11, 2020, the Virginia legislature passed a new law that replaced Virginia's current voluntary RPS with a mandatory RPS.[157] The new law requires by 2050 that 100 percent of energy sold by phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by phase II utilities must come from RPS eligible

152 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).

153 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.

154 The table reflects calendar year standards for Maryland, Washington, DC, Ohio, and North Carolina. The standards for the remaining jurisdictions are for compliance years that begin on June 1, CCYY and end on May 31 of the following year.

155 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

156 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.

157 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.

resources by 2045.[158] [159] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.[160] The Board of Public Utilities is directed to develop and provide an orderly transition to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030. Table 8-10 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, DC.

Table 8-10 Recent changes in RPS rules[161] [162] [163] [164] [165] [166] [167]

Jurisdiction	Legislation	Effective Date	Summary of changes
Illinois	Climate and Equitable Jobs Act (Public Act 102-0662)	September 15, 2021	Updated the RPS target to 40.0 percent by 2030. The previous target of 25.0 percent by 2025 is still required. Updated the requirement for RECs from new wind generation from 2,000 GWH annually to 4,500 GWH beginning in the 2021/2022 delivery year; increasing to 20,250 GWH in 2030/2031. Updated the requirement for RECs from new photovoltaic generation from 2,000 GWH annually to 5,500 GWH beginning in the 2021/2022 delivery year; increasing to 24,750 GWH in 2030/2031. Removed tree waste as an energy source for eligible resources and added waste heat to power systems and qualified combined heat and power systems as eligible resources. Updated the geographic restrictions to allow RECs from utility scale wind or photovoltaic resources that are deliverable via high voltage direct current transmission.
Maryland	Senate Bill 65	June 1, 2021	Maintains theTier 1 target of 50.0 percent in 2030 with 14.5 percent solar carve out, but changes the intermediary target levels beginning in 2022. The alternatvie compliance payment for solar was reduced and the definition of Tier 1 resource now excludes generators fueled by black liquor. Extends indefinitely the Tier 2 target of 2.5 percent which was set to expire in 2020. Tier 2 resources are defined as hydroelectric power other than pumped storage.
Delaware	151st General Assembly Senate Bill 33	February 1, 2021	Increases the RPS target from 25.0 percent in 2025 to 40.0 percent in 2035. Sets the solar carve out requirement to 10.0 percent in 2035. Establishes intermediary target levels for total RPS and the solar carve out for compliance years 2026 through 2034. Lowered the solar alternative compliance payment (SACP) from $400 per credit to $150 per credit.
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermediate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

158 A phase I utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a phase II utility is an investor-owned incumbent electric utility that was bound by such a settlement (§ 56-585.1 of the Virginia Code).
159 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS
160 N.J. S. 2314/A. 3723.
161 Illinois Climate and Equitable Jobs Act (Public Act 102-0662), Section 90-30 (September 15, 2021).
162 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
163 See Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
164 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
165 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <https://code.dccouncil.us/dc/council/laws/22-257.html>.
166 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
167 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[168]

On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities to create an OREC program targeting installation of at least 3,500 MW of offshore wind capacity by 2030 (plus 2,000 MW of energy storage capacity).[169] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500 MW by 2030 has since been replaced by a target of 7,500 MW by 2035.[170] The BPU opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Orsted.[171] [172]

On December 17, 2021, the Maryland Public Service Commission awarded ORECs in its Round 2 solicitation to the 846 MW Skipjack Wind 2 offshore project, owned by Skipjack Offshore Energy LLC, an Orsted subsidiary, and to the 808.5 MW Momentum Wind offshore project, owned by US Wind Inc.[173] ORECs for Skipjack Wind 2 have a levelized price of $71.61; ORECs for Momentum Wind have a levelized price of $54.17.[174] Both projects are expected to become operational before the end of 2026.[175] In 2017, Round 1 ORECs were awarded to Deepwater Wind's 120-MW Skipjack Wind Farm, later acquired by Orsted, and U.S. Wind's 248 MW project.[176]

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.[177] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[178]

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM jurisdictions with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources.[179] Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-11 shows the Tier I standards for PJM states.[180] All eligible technologies for the RPS standards in Table 8-11 satisfy the EIA definition of renewable energy.[181]

Table 8-11 Tier I / Class I renewable standards of PJM jurisdictions: 2021 to 2030

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	30.80%	30.10%	31.90%	33.70%	35.50%	38.00%	41.50%	43.00%	47.50%	50.00%
New Jersey	21.00%	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%
Pennsylvania	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, D.C.	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%

Delaware, Illinois, Michigan, North Carolina, Virginia and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[182]

168 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.

169 N.J. S. 2314/A. 3723.

170 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.

171 BPU Docket No. QO18080851.

172 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.

173 Orsted, US Wind Triumph with 1.6 GW in Maryland Offshore Tender," Renewables Now (December 20, 2021) <https://renewablesnow.com/news/rsted-us-wind-triumph-with-16-gw-in-maryland-offshore-tender-766237/>.

174 *Id.*

175 *Id.*

176 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).

177 "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>.

178 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>.

179 New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.

180 This includes New Jersey's Class I renewable standard.

181 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).

182 Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

PJM GATS makes data available for the amount of eligible RECs by jurisdiction. Eligible RECs are not the amount of actual RECs generated for that timeframe. A REC that is created may be eligible in multiple jurisdictions resulting in an over representation of generated RECs. This means if one REC is retired in Pennsylvania, the total amount of eligible RECs will reduce by more than one REC.

The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, DC, but in the other states REC prices are not publicly available.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through December 31, 2021. Tier I REC prices are lower than SREC prices. For example, the average SREC price in Washington, DC in 2021 was $425.61 and the average Tier I price in Washington, DC in 2021 was $5.55.

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through 2021

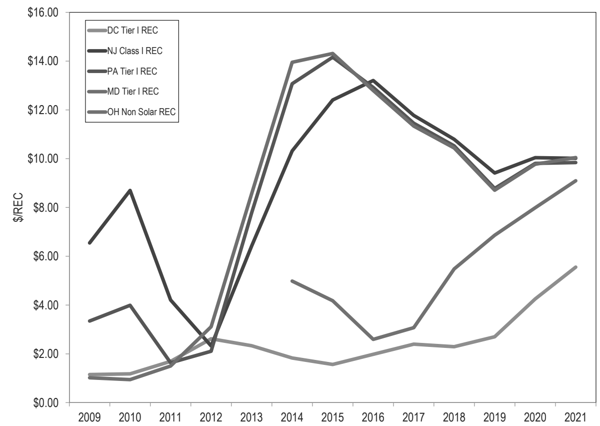


Figure 8-4 and Table 8-12 show the fulfillment of Tier I equivalent RPS requirement for 2016 through 2020 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[183] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon REC") or with landfill gas, captured methane, wood, black liquor, and other fuels. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The Delaware (DE) New Eligible requirement and the Illinois RPS, beginning in 2019, are fulfilled by noncarbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of imported and local carbon producing RECs and imported and local noncarbon RECs by state to meet the RPS requirements. Table 8-12 shows the percent of imported and local carbon producing RECs and imported and local noncarbon RECs by state used to meet the RPS requirements. For example, Pennsylvania met its Tier I target using 79.9 percent imported RECs, and 20.1 percent State RECs for the 2020 compliance year. Pennsylvania met its Tier I target using 69.0 percent noncarbon producing RECs, and 31.0 percent carbon producing RECs for the 2020 compliance year. Illinois met its Tier I target using 29.5 percent imported RECs, and 70.5 percent State RECs for the 2019 compliance year. Illinois met its Tier I target

183 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed January 27, 2022). The timing of the REC retirement reports varies by state and the 2020 reporting year data may be incomplete for some states.

using 100.0 percent noncarbon producing RECs for the 2019 and 2020 compliance years.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2016 through 2020

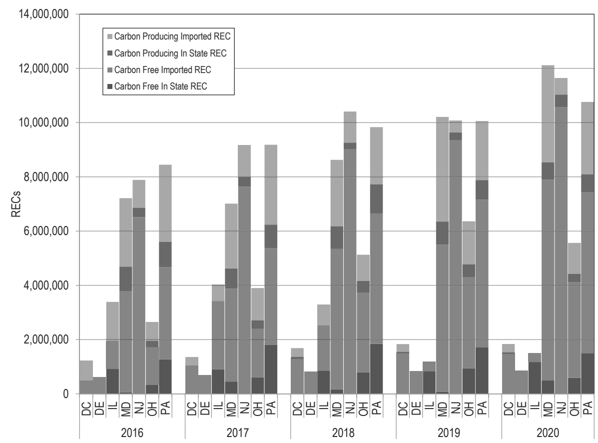


Table 8-12 State fulfillment of Tier I equivalent RPS: 2016 through 2020

		Carbon Free REC		Carbon Producing REC	
Year	REC Type	In State	Import	In State	Import
2016	DE New Eligible	1.0%	99.0%	0.0%	0.0%
	DC Tier I	0.0%	40.5%	0.0%	59.5%
	OH Renewable Energy Source	12.3%	52.8%	8.7%	26.2%
	IL Renewable	27.1%	30.3%	0.1%	42.5%
	MD Tier I	0.8%	51.7%	12.5%	35.0%
	NJ Class I	0.0%	82.5%	4.5%	13.0%
	PA Tier I	15.1%	40.2%	11.1%	33.7%
2017	DE New Eligible	0.7%	99.3%	0.0%	0.0%
	DC Tier I	0.0%	77.2%	0.0%	22.8%
	OH Renewable Energy Source	15.6%	45.8%	8.1%	30.6%
	IL Renewable	22.5%	62.3%	0.0%	15.2%
	MD Tier I	6.5%	48.9%	10.7%	34.0%
	NJ Class I	0.1%	83.2%	3.9%	12.8%
	PA Tier I	19.6%	38.9%	9.4%	32.0%
2018	DE New Eligible	0.4%	99.6%	0.0%	0.0%
	DC Tier I	0.0%	76.5%	4.5%	19.0%
	OH Renewable Energy Source	15.4%	57.4%	8.3%	18.9%
	IL Renewable	26.1%	51.0%	0.0%	22.9%
	MD Tier I	1.9%	60.1%	9.6%	28.5%
	NJ Class I	0.0%	86.7%	2.3%	11.0%
	PA Tier I	18.7%	48.9%	10.9%	21.4%
2019	DE New Eligible	0.3%	99.7%	0.0%	0.0%
	DC Tier I	0.0%	81.5%	2.8%	15.7%
	OH Renewable Energy Source	14.7%	53.0%	7.3%	25.0%
	IL Renewable	70.5%	29.5%	0.0%	0.0%
	MD Tier I	0.7%	53.2%	8.4%	37.8%
	NJ Class I	0.1%	92.7%	2.8%	4.4%
	PA Tier I	17.0%	54.2%	7.2%	21.7%
2020	DE New Eligible	0.9%	99.1%	0.0%	0.0%
	DC Tier I	0.0%	80.1%	3.3%	16.6%
	OH Renewable Energy Source	10.5%	63.5%	5.5%	20.5%
	IL Renewable	78.3%	21.7%	0.0%	0.0%
	MD Tier I	4.1%	61.1%	5.3%	29.6%
	NJ Class I	0.1%	90.8%	4.0%	5.2%
	PA Tier I	13.9%	55.1%	6.2%	24.8%

Table 8-13 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-13 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-13 are included in the total RPS requirements presented in Table 8-9. Maryland, New Jersey and Pennsylvania have Tier II or Class II standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. Washington, DC previously had Tier II standards. The Washington, DC tier II standard was discontinued at the end of the 2019 compliance year. By 2024, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900

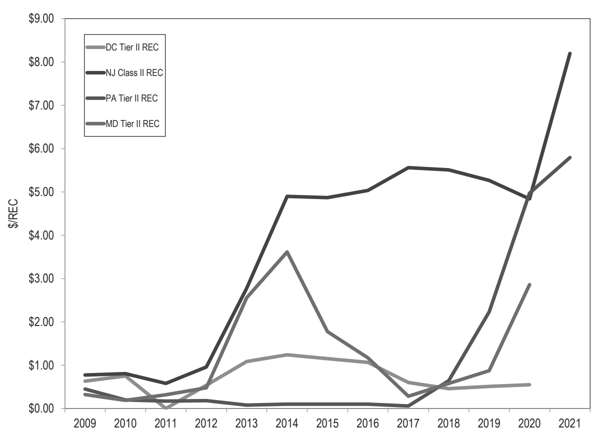
GWh of power be produced by poultry waste in 2020. Maryland established a minimum standard for offshore wind in 2017 that takes effect in 2021 with a requirement that 1.37 percent of load be served by offshore wind. The standard increases to 2.03 percent in 2023.[184]

Table 8-13 Additional renewable standards of PJM jurisdictions: 2021 to 2030

Jurisdiction	Type of Standard	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	Off Shore Wind	1.37%	1.36%	2.03%	2.01%	2.01%	1.99%	1.98%	1.96%	1.94%	1.94%
Maryland	Tier 2	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Class II	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
North Carolina	Swine Waste	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for January 1, 2009, through December 31, 2021. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2021. In 2021, the average Pennsylvania Tier II REC price was $5.79 and the average New Jersey Class II REC price was $8.20.[185]

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through 2021



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-9 and Table 8-11 but must be met by solar RECs (SRECs) only. Table 8-14 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC have or have had requirements for the proportion of load to be served by solar. The Illinois RPS specifies the number of RECs that must be sourced from photovoltaic resources energized after June 1, 2017. Recent legislation increased the SREC requirement from 2,000,000 RECs to 5,500,000 RECs in the 2021/2022 Delivery Year.[186] New Jersey closed registration for new SRECs on April 30, 2020, having met its milestone that solar power equal or exceed 5.1 percent of New Jersey electricity sales.[187] On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for solar generators not eligible for New Jersey SRECs.[188] The new program establishes a 15 year fixed priced Transition REC (TREC). Pennsylvania allows only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are Tier I resources in Pennsylvania. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018, 5.1 percent for 2020 through 2022 and the solar standard decreases to 1.1 percent for 2032.[189] Maryland legislation in 2019 increased the solar carve out percentages from 2.5 percent to 14.5 percent in 2030. Ohio HB 6 removed the solar carve out from the Ohio RPS.[190] The Delaware General Assembly passed new RPS legislation on February 10, 2021 that increased the solar carve out target from 3.5 percent in 2025 to 10.0 percent in 2035.[191]

184 Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2, <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.

185 Tier II REC price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com>.

186 See amendments to Sec. 1-75(c)(1)(C) of the Illinois Power Agency Act contained in Section 90-30 of Public Act 102-0662.

187 See Clean Energy Act of 2019 (NJ AB-2723); N.J.A.C. 14:82.4(b)6; BPU, Monthly Report on Status toward Attainment of the 5.1 percent Milestone for Closure of the SREC Program (March 31, 2020).

188 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.

189 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.

190 Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.

191 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.

Table 8-14 Solar renewable standards by percent of electric load for PJM jurisdictions: 2021 to 2030[192]

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	2.50%	2.75%	3.00%	3.25%	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%
Illinois (RECs)	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	5,500,000	24,750,000
Maryland	7.50%	5.50%	6.00%	6.50%	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%
Michigan	No Minimum Solar Requirement									
New Jersey	5.10%	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	No Minimum Solar Requirement									
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%
Jurisdiction with Voluntary Standard										
Indiana	No Minimum Solar Requirement									
Virginia	No Minimum Solar Requirement									
Jurisdiction with No Standard										
Kentucky	No Renewable Portfolio Standard									
Tennessee	No Renewable Portfolio Standard									
West Virginia	No Renewable Portfolio Standard									

Figure 8-6 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through December 31, 2021. The average NJ SREC prices dropped from $673.04 per SREC in 2009 to $193.07 per SREC in 2021. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, DC SREC price was $425.61 per SREC in 2021.[193]

Figure 8-6 Average SREC price by jurisdiction: 2009 through 2021

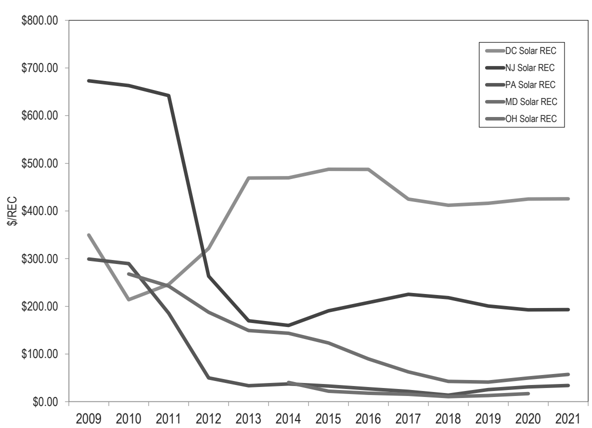
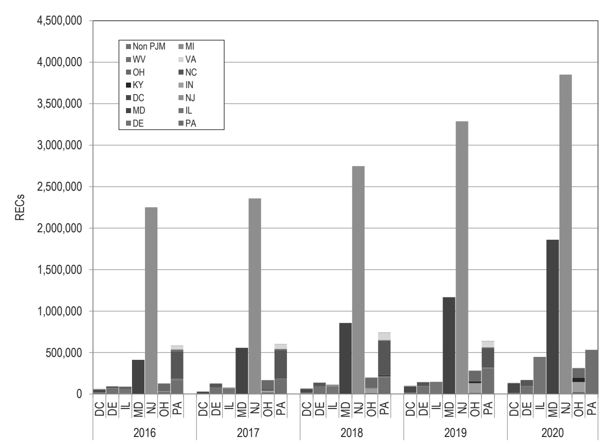


Figure 8-7 and Table 8-15 shows where the SRECs originated that are used to satisfy the states' solar requirement by retiring RECs for 2016 through 2020.[194] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-15 shows the percent of imported and local SRECs used to meet the RPS requirements. Illinois, Maryland, New Jersey and Pennsylvania met their solar requirements using 100 percent in-state SRECs in 2020.

Figure 8-7 State fulfillment of Solar RPS: 2016 through 2020



192 The Illinois solar standard currently requires 5.5 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 102-0662, September 15, 2021.

193 Solar REC average price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com> (Accessed January 27, 2022).

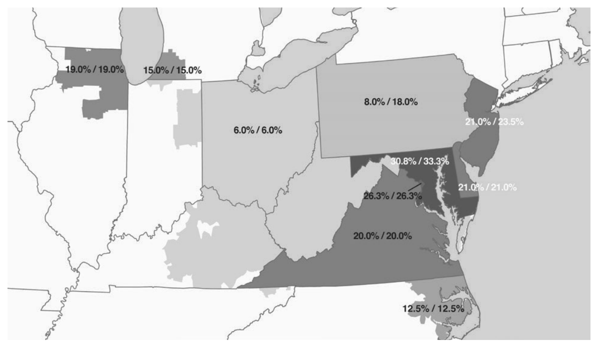
194 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed January 27, 2022). The timing of the REC retirement reports varies by state and the 2020 reporting year data may be incomplete for some states.

Table 8-15 State fulfillment of Solar RPS: 2016 through 2020

		In State SREC	Import SREC
2016	DC Solar	49.8%	50.2%
	DE Solar Eligible	76.5%	23.5%
	IL Solar Renewable	56.1%	43.9%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	73.3%	26.7%
	PA Solar	29.1%	70.9%
2017	DC Solar	63.8%	36.2%
	DE Solar Eligible	61.9%	38.1%
	IL Solar Renewable	87.5%	12.5%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	69.0%	31.0%
	PA Solar	30.6%	69.4%
2018	DC Solar	67.4%	32.6%
	DE Solar Eligible	67.7%	32.3%
	IL Solar Renewable	82.8%	17.2%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	59.5%	40.5%
	PA Solar	27.1%	72.9%
2019	DC Solar	72.4%	27.6%
	DE Solar Eligible	66.4%	33.6%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	43.5%	56.5%
	PA Solar	48.8%	51.2%
2020	DC Solar	81.5%	18.5%
	DE Solar Eligible	56.7%	43.3%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	36.8%	63.2%
	PA Solar	100.0%	0.0%

Figure 8-8 shows the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. For each state in Figure 8-8, the first number represents the RPS percent for Tier I or renewable energy resources; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. The Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. As a result, the 18.0 percent number in Figure 8-8 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 8.0 percent number in Figure 8-8 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-8 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: 2021[195]



Under the existing state renewable portfolio standards, 15.9 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in 2021. Tier I resources include landfill gas, run of river hydro, wind and solar resources. Tier II resources include pumped storage, solid waste and waste coal resources. In 2021, 7.9 percent of PJM generation was renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-16. If the proportion of load among states remains constant, 30.5 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2030 under currently defined RPS rules. Approximately 13.5 percent of PJM load should have been served by Tier I or renewable energy resources in 2021. In 2021, 5.7 percent of PJM generation was Tier I or renewable energy. The current REC production from PJM generation resources was not enough to meet the state renewable requirements for 2021, and LSEs purchased RECs from outside the PJM footprint. LSEs that are unable to meet the RPS with RECs may use alternative compliance payments

195 The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

for unmet goals based on each state's requirements. If the proportion of load among states remains constant, 28.1 percent of PJM load must be served by Tier I or renewable energy resources in 2030 under defined RPS rules.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-16 shows generation by jurisdiction and resource type for 2021. Wind generation was 28,402.4 GWh of 47,181.3 Tier I GWh, or 60.2 percent, in the PJM footprint. As shown in Table 8-16, 65,289.2 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 72.3 percent. Wind and solar generation (noncarbon producing) was 4.2 percent of total generation in PJM in 2021. Tier I generation was 5.7 percent of total generation in PJM and Tier II was 2.2 percent of total generation in PJM in 2021. Biofuel, landfill gas, solid waste and waste coal (carbon producing) accounted for 13,600.8 GWh, or 20.8 percent of the total Tier I and Tier II generation.

alternative fuel as waste coal. A REC is only generated when using the fuel listed as Tier I or Tier II. Virginia has the largest amount of solar capacity in PJM, 1,765.5 MW, or 36.8 percent of the total solar capacity. Wind resources located in western PJM, Illinois, Indiana and Ohio, account for 9,379.3 MW, or 86.9 percent of the total wind capacity.

PJM states with RPS rely heavily on imports for RPS compliance. Table 8-17 compares each state's RPS requirement in 2021 with generation by RPS eligible PJM generators. Illinois had sufficient in state generation to cover 77.9 percent of the RPS requirement and Pennsylvania generation was sufficient to cover 77.0 percent of the Tier I RPS requirement and 86.8 percent of the Tier II RPS requirement. North Carolina is the only state with generation in excess of the RPS requirement but this is primarily due to the fact that only a relatively small portion of the North Carolina load is in PJM. Overall there was sufficient generation in PJM states to meet 45.6 percent of the Tier I RPS requirement and 98.5 percent of the Tier II RPS requirement.

Table 8-16 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): 2021

	Tier I							Tier II					
Jurisdiction	Biofuel	Landfill Gas	Run of River	Other Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Other Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	0.0	48.1	0.0	0.0	0.0	0.0	48.1	0.0	0.0	0.0	0.0	0.0	48.1
Illinois	0.0	142.0	0.0	0.0	13.2	13,166.2	13,321.4	0.0	0.0	0.0	0.0	0.0	13,321.4
Indiana	0.0	19.9	0.0	27.5	61.4	5,625.8	5,734.7	0.0	0.0	0.0	0.0	0.0	5,734.7
Kentucky	0.0	0.0	355.2	79.2	0.0	0.0	434.4	0.0	0.0	0.0	0.0	0.0	434.4
Maryland	0.0	42.9	0.0	0.0	517.0	590.1	1,150.1	0.0	0.0	688.4	0.0	688.4	1,838.5
Michigan	0.0	66.2	0.0	56.4	5.6	0.0	128.3	0.0	0.0	0.0	0.0	0.0	128.3
New Jersey	0.0	124.9	18.4	0.0	869.8	9.7	1,022.9	275.9	0.0	1,361.2	0.0	1,637.0	2,659.9
North Carolina	0.0	0.0	561.7	0.0	2,075.3	506.1	3,143.1	0.0	0.0	0.0	0.0	0.0	3,143.1
Ohio	0.0	327.4	1,147.3	0.0	585.8	2,586.5	4,647.0	0.0	0.0	0.0	0.0	0.0	4,647.0
Pennsylvania	0.0	425.1	5,055.2	24.7	224.3	3,465.8	9,195.2	2,322.5	0.0	1,568.8	5,585.9	9,477.3	18,672.5
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,324.5	0.0	0.0	1,324.5	1,324.5
Virginia	1,191.7	489.1	941.3	65.3	3,026.2	49.8	5,763.5	2,438.9	1,054.5	857.5	0.0	4,350.9	10,114.4
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	31.8	876.2	0.0	33.4	1,651.3	2,592.6	0.0	0.0	0.0	629.8	629.8	3,222.4
Total	1,191.7	1,717.5	8,955.3	253.2	7,412.2	27,651.4	47,181.3	5,037.3	2,379.0	4,475.9	6,215.7	18,107.9	65,289.2

Table 8-18 shows the summer installed capacity rating of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal, natural gas and oil units that qualify as Tier II because they have a secondary fuel capability that satisfies the alternative energy standards of a PJM state or jurisdiction. For example, a coal generator that can also burn waste coal to generate power could list the

Table 8-17 RPS Requirements and Generation by RPS Eligible Resources: 2021

	Tier I			Tier II		
Jurisdiction	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement
Delaware	48.1	2,522.3	1.9%	0.0	0.0	
Illinois	13,321.4	17,108.3	77.9%	0.0	0.0	
Indiana	5,734.7	0.0		0.0	0.0	
Kentucky	434.4	0.0		0.0	0.0	
Maryland	1,150.1	19,236.3	6.0%	688.4	1,561.4	44.1%
Michigan	128.3	659.4	19.5%	0.0	0.0	
New Jersey	1,022.9	15,841.6	6.5%	1,637.0	1,885.9	86.8%
North Carolina	3,143.1	574.1	547.5%	0.0	0.0	
Ohio	4,647.0	9,147.1	50.8%	0.0	0.0	
Pennsylvania	9,195.2	11,946.4	77.0%	9,477.3	14,933.0	63.5%
Tennessee	0.0	0.0		1,324.5	0.0	
Virginia	5,763.5	24,005.0	24.0%	4,350.9	0.0	
Washington, D.C.	0.0	2,335.7	0.0%	0.0	0.0	
West Virginia	2,592.6	0.0		629.8	0.0	
Total	47,181.3	103,376.2	45.6%	18,107.9	18,380.3	98.5%

On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators, based on the effective load carrying capability (ELCC) method.[196] The MMU opposed the ELCC rules because they fail to incorporate the marginal ELCC value of resources, rely on significant counterfactual behavioral assumptions, do not apply to all resource types, and use invented data, among other issues, but does not oppose the ELCC approach in concept and when done correctly.[197] [198]

Under the pre ELCC rules a generator's capacity value was derated from the installed capacity level by multiplying the generator's net maximum capability by a derating factor. The derating factor was either based on the generator's historical performance during summer peak hours or a class average value calculated by PJM. The intent of the pre ELCC method was to obtain a MW value the generator can reliably produce during the summer peak hours.[199] As of December 31, 2021, the derated capacity with capacity obligations in the PJM Capacity Market totaled 2,590.5 MW for wind generators and 1,824.0 MW for solar generators.[200] This compares to installed wind capacity of 10,795.8 MW and installed solar capacity of 4,791.9 MW in Table 8-18. PJM posts class average capacity factors for wind and solar generators. There were two pre ELCC classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent.[201]

196 See 176 FERC ¶ 61,056.
197 *In Docket ER21-278-000, see* Comments and Motions of the Independent Market Monitor for PJM, (November 20, 2020); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, (December 18, 2020); Comments and Motions of the Independent Market Monitor for PJM (March 22, 2021); Answer and motion for Leave to Answer of the Independent Market Monitor for PJM (April 29, 2021)
198 *In Docket ER21-2043, see* Comments of the Independent Market Monitor for PJM (June 22, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM (July 9, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM (July 20, 2021);
199 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
200 The derated capacity MW for wind generators includes 1,079.6 MW in capacity modifications to reflect winter CIRs.
201 See "Class Average Capacity Factors Wind and Solar Resources," PJM, June 1, 2017 <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

Table 8-18 Renewable capacity by jurisdiction (MW): December 31, 2021

Jurisdiction	Biofuel	Coal / Biofuel	Hydro	Landfill Gas	Natural Gas / Landfill Gas	Other Gas	Oil / Biofuel	Oil / Landfill Gas	Pumped-Storage Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	0.0	0.0	8.1	1,797.0	0.0	0.0	13.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	0.0	0.0	39.2	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	4,526.1	4,574.3
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	30.1	0.0	0.0	2,350.5	2,392.0
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	132.7
Maryland	0.0	0.0	0.4	22.3	0.0	0.0	69.0	0.0	0.0	371.5	128.2	0.0	243.7	835.1
Michigan	0.0	0.0	13.9	12.0	0.0	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	30.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	11.0	38.9	0.0	0.0	0.0	0.0	453.0	712.7	204.6	0.0	4.5	1,424.5
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	1,331.6	0.0	0.0	208.0	1,864.6
Ohio	0.0	2,320.0	194.4	58.2	0.0	1.0	136.0	0.0	0.0	416.1	0.0	0.0	1,045.6	4,171.3
Pennsylvania	54.0	0.0	1,387.3	125.2	1,300.0	0.0	0.0	0.0	1,269.0	121.8	209.3	1,347.0	1,457.2	7,270.7
Tennessee	50.0	0.0	296.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	346.6
Virginia	241.9	585.0	436.4	127.7	0.0	88.0	17.0	0.0	5,386.0	1,765.5	123.0	0.0	12.0	8,782.5
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	29.1	0.0	96.0	802.3	1,145.2
PJM Total	345.9	2,905.0	3,015.6	442.7	3,097.0	89.0	222.0	13.0	7,108.0	4,791.9	665.0	1,443.0	10,795.8	34,934.0

There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.[202]

Table 8-19 shows renewable capacity registered in the PJM generation attribute tracking system (GATS).[203] These resources are not PJM resources even though most are located in PJM states. For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 8,368.6 MW of which 2,894.6 MW are in New Jersey. These resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are 1,774.7 MW of capacity located in jurisdictions outside PJM that may qualify for specific renewable energy credits in some PJM jurisdictions. For example, there are 54.0 MW of capacity registered with GATS located in Alabama.

Table 8-19 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): December 31, 2021[204]

Jurisdiction	Biofuel	Coal / Biofuel	Fuel Cell	Geothermal	Hydro	Landfill Gas	Natural Gas / Distributed Generation	Other Gas	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Alabama	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Delaware	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	131.6	0.0	0.0	0.0	2.0	135.8
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	152.2	0.0	0.0	0.0	0.0	179.3
Illinois	0.0	0.0	0.0	0.0	20.0	55.4	0.0	2.1	854.8	0.0	0.0	0.0	598.4	1,530.7
Indiana	0.0	0.0	0.0	0.0	0.0	47.2	0.0	1.3	158.6	0.0	0.0	94.6	180.0	481.6
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	2.1	0.0	0.0	0.0	336.8	340.5
Kentucky	93.0	600.0	0.0	0.0	164.8	20.2	0.0	0.4	38.9	0.0	0.0	0.0	0.0	917.3
Maryland	3.8	65.0	0.0	2.6	0.0	13.7	0.0	0.0	1,221.2	10.0	0.0	0.0	0.3	1,316.5
Michigan	31.0	0.0	0.0	0.0	17.2	16.6	0.0	4.8	112.9	0.0	0.0	0.0	85.6	268.0
Minnesota	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0
Missouri	0.0	0.0	0.0	0.0	0.0	5.6	0.0	0.0	61.2	0.0	0.0	0.0	693.0	759.8
New Jersey	0.0	0.0	0.0	0.0	0.0	45.8	0.0	15.4	2,894.6	0.0	0.0	0.0	4.7	2,960.5
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.4
North Carolina	151.5	0.0	0.0	0.0	520.4	0.0	0.0	0.0	1,262.2	0.0	0.0	0.0	0.0	1,934.1
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	92.8	0.0	0.0	0.0	6.6	19.7	0.0	59.3	267.1	0.0	0.0	33.0	54.7	533.2
Pennsylvania	62.2	109.7	0.8	0.0	56.5	45.2	21.1	100.0	535.8	0.2	206.7	57.6	3.2	1,199.0
South Carolina	0.0	0.0	0.0	0.0	0.0	29.8	0.0	0.0	91.3	0.0	0.0	0.0	0.0	121.1
Tennessee	0.0	0.0	0.0	0.0	99.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	99.6
Virginia	287.6	0.0	0.0	0.0	31.3	9.9	0.0	2.6	424.5	0.0	0.0	0.0	0.0	755.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	154.4	0.0	0.0	13.5	0.0	217.4
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	106.6
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	44.7
Total	820.5	774.7	0.8	2.6	1,054.4	339.9	21.1	235.1	8,368.6	10.2	206.7	198.7	2,318.6	14,352.1

202 Id.

203 PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits. GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

204 See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed January 27, 2022).

Renewable energy credits are related to the production and purchase of wholesale power, but have not, when they constitute a transaction separate from a wholesale sale of power, been found subject to FERC regulation.[205] RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets.

Delaware, North Carolina, Michigan and Virginia allow various types of resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[206] This is equivalent to providing a REC price equal to three times its stated value per MWh.

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina have created their own state-wide tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must ultimately be traded. Table 8-20 shows the REC tracking systems used by each state within the PJM footprint. To ensure a REC is only used one time, REC tracking systems must keep an account of a REC from its creation until its retirement. A REC is considered to be retired when it has been used to satisfy an obligation associated with an RPS.

Table 8-20 REC tracking systems in PJM states with renewable portfolio standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Virginia	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-21 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with each state's standards to be generated by in-state resources. Illinois recently relaxed the geographic restrictions to allow RECs sourced from wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission. North Carolina has provisions that require RECs to be purchased from in-state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions. Pennsylvania added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard to be sourced from resources located in Pennsylvania.

Pennsylvania and Virginia require that RECs used for RPS compliance be produced from resources located within the PJM footprint. Delaware requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

205 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA... And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, ... do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).

206 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

Table 8-21 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria or from utility scale wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Virginia	No	RECs must be purchased from resources located within PJM
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.

Alternative Compliance Payments

PJM jurisdictions have various methods for enforcing compliance with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, function as a cap on the market value of RECs. In New Jersey, solar ACPs are currently $238.00 per MWh.[207] Pennsylvania requires that solar ACPs be 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates which was $74.00 per MWh for reporting year ending May 31, 2020. Delaware recently reduced the solar ACP from $400 per credit to $150 per credit.[208] Maryland reduced the solar ACP from $100 per credit to $80 per credit effective June 1, 2021.[209]

Figure 8-9 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. The public utility commissions in Michigan and North Carolina have discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

207 N.J. S. 2314/A. 3723.
208 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
209 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

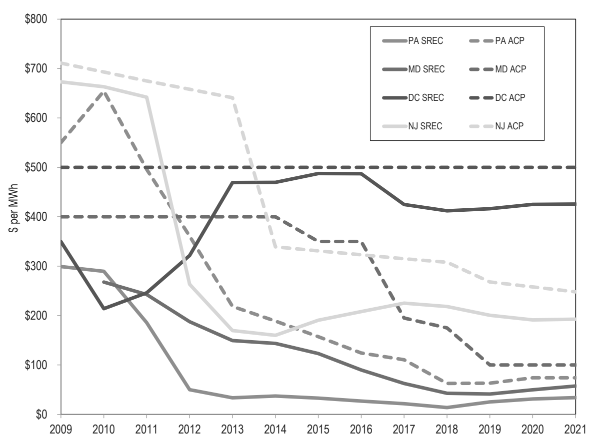
Table 8-22 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-22 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions as of December 31, 2021[210 211]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$150.00
Illinois	$0.35		
Maryland	$30.00	$15.00	$80.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$238.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$54.14		
Pennsylvania	$45.00	$45.00	$74.00
Washington, D.C.	$50.00	$10.00	$500.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Virginia	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission.

Figure 8-9 Comparison of SREC price and solar ACP: 2009 through 2021



In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public.

The Pennsylvania Public Utility Commission issued their 2020 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in February of 2021.[212] Pennsylvania reported that the 614,926 SRECs, 10,086,046 Tier I RECs and 11,203,559 Tier II RECs were retired during the 2020 reporting year (June 1, 2019 through May 31, 2020). Supplier obligations for 1,435 SRECs, 34,737 Tier I RECs and 37,073 Tier II RECs were resolved through ACPs.

The Public Service Commission of the District of Columbia reported that 133,416 SRECs and 1,972,093 Tier I RECs were retired during the 2020 compliance year. The average price for solar RECs was $388.11. ACPs decreased from $12.1 million for 2019 to $8.2 million for 2020.[213]

The Public Service Commission of Maryland reported that 1,859,976 SRECs were retired in 2020, an increase of 59.3 percent over the 2019 level. Tier 1 REC retirements increased to 12,117,585, 18.7 percent higher than in 2019. The RPS requirement for solar increased to 6.0 percent in 2020, up from 5.5 percent in 2019. The Tier 1 requirement increased 4.9 percentage points to 20.7 percent in 2020.[214] ACPs were $22,170 for 2020. [215]

210 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2018 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.

211 The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2020. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed October 22, 2020).

212 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2020," (September 2020), <https://www.puc.pa.gov/media/1410/aeps-annreport2020.pdf >.

213 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2020," Public Service Commission of the District of Columbia (May 3, 2021), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.

214 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2020," Public Service Commission of Maryland (November 2021) at 8, <https://www.psc.state.md.us/commission-reports/>.

215 *Id.*

The Public Utilities Commission of Ohio reported that 6,023,768 RECs were retired in the 2020 compliance year, which is 4,000 RECs short of the RPS requirement. Alternative compliance payments were made due to the shortfall.[216]

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. Delmarva Power reported to the Delaware Public Service Commission that they satisfied their REC obligation of 740,604 credits for the compliance year ending May 31, 2021, with zero ACPs.[217] Delmarva Power satisfied their solar REC obligation of 150,262 credits with zero alternative compliance payments.

Prior to the 2017/2018 Delivery Year, the Illinois RPS had required electricity suppliers to satisfy at least 50 percent of their RPS obligation through ACPs. This requirement was removed for 2017/2018 Delivery Year and ACPs for ComEd decreased to $74,148. The 2016-2017 ACPs for ComEd totaled $40,575,311.[218]

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2018 compliance report on August 13, 2019. The compliance report stated that Dominion met its general RPS requirement by purchasing 397,643 credits that consisted of wind and hydro RECs and energy efficiency credits (EECs).[219] Dominion also met its solar, poultry waste, and swine waste requirements by purchasing RECs.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2018 standard by generating or acquiring 283,473 RECs.[220]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2020.[221] Electric power suppliers retired 10,078,927 class I RECs and 1,758,386 class II RECs. Twenty ACPs were submitted class I credits; 135 ACPs were submitted for class II. Electric power suppliers retired 3,287,327 solar RECs and 12 SACPs were submitted.

Table 8-23 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[222] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost by type in Table 8-23 is an estimate based on average REC prices and assigning the reported alternative compliance payments to the solar standard. The cost of complying with RPS, as reported by the states, was $5.6 billion over the six year period from 2014 through 2019 for the nine jurisdictions that had RPS and reported compliance costs.[223] The average RPS compliance cost per year based on the reported compliance cost for the six year period from 2014 through 2019 was $936.7 million. The compliance cost for 2019, the most recent year with almost complete data, was $1.2 billion.

216 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2020," Public Utilities Commission of Ohio (November 2, 2021), <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.

217 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2020–May 31, 2021," Delmarva Power, (Sept. 23, 2021), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>

218 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.

219 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission (Oct. 1, 2019) at 38, <https://www.ncuc.net/Reps/reps.html>.

220 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 18, 2020), <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>.

221 See RPS Report Summary 2005-2020, New Jersey's Clean Energy Program (Apr. 13, 2021), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

222 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.

223 The actual PJM RPS compliance cost exceeds the reported $4.4 billion since this total does not include a value for Delaware in 2014 and a value for Pennsylvania in 2018.

Table 8-23 RPS Compliance Cost[224 225 226 227 228 229 230 231 232 233 234]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019	2020
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916	$19,401,476	$21,133,971
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240	$8,121,914	$9,096,298
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676	$11,279,562	$12,037,673
Illinois	Total RPS	$21,701,688	$24,817,068	$25,718,863	$25,919,372	$25,775,523		
Maryland	Total RPS	$103,990,914	$126,727,632	$135,198,524	$72,009,070	$84,806,928	$134,545,520	$223,166,704
	Solar	$29,372,737	$39,055,714	$45,556,987	$21,275,664	$27,351,388	$55,166,116	$122,943,987
	Tier I	$70,630,620	$85,054,001	$88,200,121	$50,045,621	$56,406,247	$79,320,505	$99,836,127
	Tier II	$3,987,557	$2,617,917	$1,441,416	$687,785	$1,049,293	$58,899	$386,590
Michigan	Total RPS	$476,535	$0	$3,264,504	$3,961,262	$3,264,504		
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	$653,810,457	$763,108,366	
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	$560,509,712	$667,975,153	
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	$83,474,335	$85,522,028	
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	$9,826,410	$9,611,185	
North Carolina	Total RPS	$297,513	$358,436	$317,644	$234,264	$442,579		
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	$50,214,523	$69,812,721	$81,752,397
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092	$9,578,048	$0
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431	$60,234,672	$81,752,397
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911	$115,585,212	$99,681,713	$112,691,066	
	Solar	$14,163,543	$19,227,690	$21,876,876	$17,987,722	$16,565,924	$20,608,103	
	Tier I	$70,922,431	$94,339,032	$101,700,328	$95,370,456	$77,899,586	$74,780,310	
	Tier II	$1,098,503	$1,020,210	$1,464,707	$2,227,034	$5,216,203	$17,302,653	
Washington D.C.	Total RPS	$27,372,970	$38,540,633	$47,163,353	$42,678,813	$50,609,701	$57,300,000	$65,000,000
	Solar	$25,145,143	$36,526,662	$44,897,161	$38,571,061	$45,673,261	$51,982,914	$59,897,169
	Tier I	$2,140,860	$1,899,232	$2,132,072	$3,960,018	$4,809,857	$5,262,354	$5,102,831
	Tier II	$86,966	$114,738	$134,119	$147,734	$126,583	$54,733	$0
PJM	Total RPS	$678,387,871	$888,389,738	$986,186,949	$925,417,144	$986,947,843	$1,156,859,148	$391,053,072

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[235] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[236 237]

224 Several states have not released compliance reports for the period June 1, 2019 through May 31, 2020.
225 Retail Electricity Supplier's RPS Compliance Report," Delmarva Power (Sept. 23, 2021), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.
226 "Fiscal Year 2018 Annual Report," February 15, 2019, "Report on Costs and Benefits of Renewable Resource Procurement," April 1, 2016, Illinois Power Agency (IPA), <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>. The compliance cost entry for Illinois represents the ComEd cost of RECs as given in Section 11, Table 2.
227 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Nov. 2021) at 8, <https://www.psc.state.md.us/commission-reports/>.
228 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 18, 2020, <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>. The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.
229 "RPS Report Summary 2005-2020," New Jersey's Clean Energy Program, April 13, 2021, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
230 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2020," Public Utilities Commission of Ohio, Nov. 2, 2021, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
231 "2020 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, February 2021 <https://www.puc.pa.gov/media/1410/aeps-annreport2020.pdf>.
232 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2020," Public Service Commission of the District of Columbia, Executive Summary, May 3, 2021, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
233 "Application of Dominion Energy North Carolina for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance and Related Costs," Docket No. E-22, Sub 557, Sub 558, August 30, 2018 <https://www.ncuc.net/>. The North Carolina compliance cost entries reflects the compliance cost of Dominion Energy North Carolina.
234 The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.
235 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 4, 2022).
236 On April 16, 2020, the EPA issued a revised final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed May 7, 2020).
237 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO_2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards," <https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020)

Table 8-24 shows SO_2 emission controls by fossil fuel fired units in PJM.[238 239 240] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[241] Of the current 55,226.2 MW of coal capacity in PJM, 51,659.9 MW of capacity, 93.5 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-24 SO_2 emission controls by fuel type (MW): December 31, 2021[242]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	51,659.9	3,566.3	55,226.2	93.5%
Diesel Oil	0.0	4,627.4	4,627.4	0.0%
Natural Gas	0.0	67,844.8	67,844.8	0.0%
Other	325.0	3,833.7	4,158.7	7.8%
Total	51,984.9	79,872.2	131,857.1	39.4%

Table 8-25 shows NO_X emission controls by fossil fuel fired units in PJM. Coal has the highest NO_X emission rate, while natural gas and diesel oil have lower NO_X emission rates. Of the current 55,226.2 MW of coal capacity in PJM, 55,097.2 MW of capacity, 99.8 percent, has some form of emissions controls to reduce NO_X emissions. Most units in PJM have NO_X emission controls in order to meet each state's emission compliance standards, based on whether a state is part of CSAPR, Acid Rain Program (ARP) or a combination of the three. The NO_X compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[243]

Table 8-25 NO_X emission controls by fuel type (MW): As of December 31, 2021

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	55,097.2	129.0	55,226.2	99.8%
Diesel Oil	1,020.3	3,607.1	4,627.4	22.0%
Natural Gas	66,846.8	998.0	67,844.8	98.5%
Other	1,805.7	2,353.0	4,158.7	43.4%
Total	124,770.0	7,087.1	131,857.1	94.6%

Table 8-26 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.8 percent) in PJM have particulate controls, as well as a few natural gas units (4.3 percent) and units with other fuel sources (49.5 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[244] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 55,226.2 MW of coal capacity in PJM, 55,141.2 MW of capacity, 99.8 percent, have some type of particulate emissions control technology. In order to achieve compliance with MATS, most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR. Currently, 106 of the 118 coal steam units have baghouse or FGD technology installed, representing 50,359.9 MW out of the 55,226.2 MW total coal capacity, or 91.2 percent.

Table 8-26 Particulate emission controls by fuel type (MW): As of December 31, 2021

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	55,141.2	85.0	55,226.2	99.8%
Diesel Oil	0.0	4,627.4	4,627.4	0.0%
Natural Gas	2,912.0	64,932.8	67,844.8	4.3%
Other	2,058.5	2,100.2	4,158.7	49.5%
Total	60,111.7	71,745.4	131,857.1	45.6%

Emissions

Figure 8-10 shows the total CO_2 emissions and the CO_2 emissions per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the fourth quarter of 2021. Figure 8-10 also shows the CO_2 emissions per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the fourth quarter of 2021.[245 246] For the period from the first quarter of 1999 through the fourth quarter of 2021, the minimum CO_2 produced per MWh was 0.65 short tons per MWh in the fourth quarter of 2021, and the maximum was 0.96 short tons per MWh in the first quarter of 2010. Total PJM generation increased from 194,878.5 GWh in the fourth quarter of 2020 to 195,313.0 GWh in the fourth quarter of 2021, while CO_2 produced decreased from

238 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 4, 2022).
239 Air Markets Programs Data is submitted quarterly. Generators have 60 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year. The most recent complete set of emissions data is from 2020.
240 The total MW are less than the 186,593.4 reported in Section 5: Capacity Market, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed March 4, 2022).
241 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA, "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A, Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&tmc=true&node=se40.18.72_12&rgn=div8> (Accessed May 7, 2020).
242 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.
243 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).
244 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed March 4, 2022).
245 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
246 Emissions data for the fourth quarter of 2021 was not yet finalized at the time of this report because generators have 60 days after the end of the quarter to submit their emissions data.

83.5 million short tons in the fourth quarter of 2020 to 75.6 million short tons in the fourth quarter of 2021.[247]

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: January 1999 through December 2021[248 249]

Figure 8-11 shows the total CO_2 emissions on peak and off peak and the CO_2 emissions per MWh for all CO_2 emitting units. Since the first quarter of 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.65 short tons per MWh in the fourth quarter of 2021, and a maximum of 0.97 short tons per MWh in the second quarter of 2010. Since the first quarter of 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.65 short tons per MWh in the fourth quarter of 2021, and a maximum of 0.94 short tons per MWh in the first quarter of 2010. In the fourth quarter of 2021, CO_2 emissions were 0.65 short tons per MWh for off peak hours and 0.65 for on peak hours.

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: January 1999 through December 2021[250]

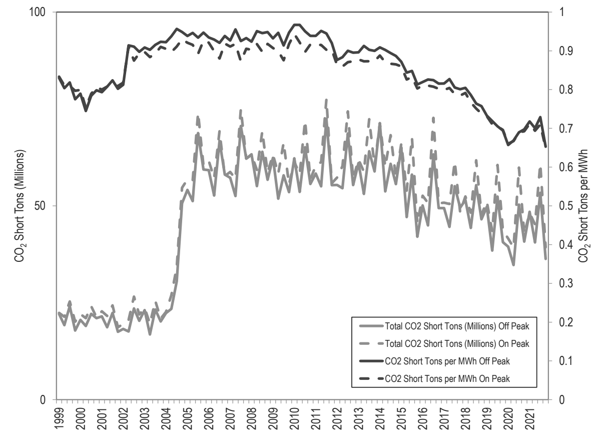


Figure 8-12 shows the total SO_2 and NO_X emissions and the short ton emissions per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emissions per MWh of total PJM generation. For the period from the first quarter of 1999 through the fourth quarter of 2021, the minimum SO_2 produced per MWh was 0.000354 short tons per MWh in the fourth quarter of 2021, and the maximum was 0.008141 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the fourth quarter of 2021, the minimum NO_X produced per MWh was at a 0.000254 short tons per MWh in the third quarter of 2021, and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. In the fourth quarter of 2021, SO_2 emissions were 0.000354 short tons per MWh and NO_X emissions were 0.000290 short tons per MWh. The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2021.[251 252]

247 See the *2021 Annual State of the Market Report for PJM:* Section 3: Energy Market, Table 3-10.

248 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

249 In 2004 and 2005, PJM integrated the American Electric Power (AEP), ComEd, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).

250 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

251 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry,"<https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).

252 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

Figure 8-12 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: January 1999 through December 2021[253]

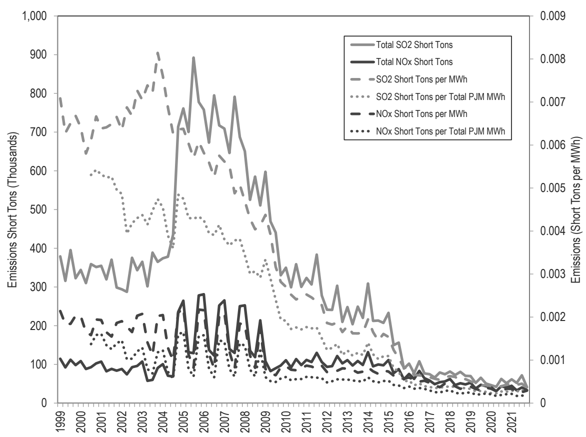
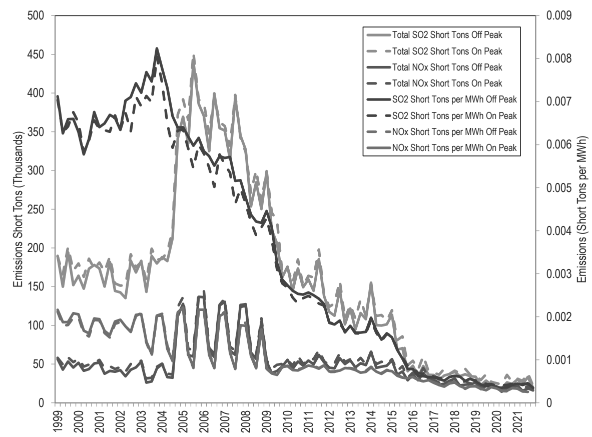


Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emissions per MWh from emitting resources for all SO_2 and NO_X emitting units. For the period from the first quarter of 1999 through the fourth quarter of 2021, the minimum SO_2 produced per MWh during off peak hours was 0.000348 short tons per MWh in the fourth quarter of 2021, and the maximum was 0.008239 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the fourth quarter of 2021, the minimum SO_2 produced per MWh during on peak hours was 0.000359 short tons per MWh in the fourth quarter of 2021, and the maximum was 0.008048 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the fourth quarter of 2021, the minimum NO_X produced per MWh during off peak hours was 0.000255 short tons per MWh in the third quarter of 2021, and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. For the period from the first quarter of 1999 through the fourth quarter of 2021, the minimum NO_X produced per MWh during on peak hours was 0.000254 short tons per MWh in the third quarter of 2021 and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. In the fourth quarter of 2021, SO_2 emissions were 0.000348 short tons per MWh and 0.000359 short tons per MWh for off and on peak hours. In the fourth quarter of 2021, NO_X emissions were 0.000287 short tons per MWh and 0.000293 short tons per MWh for off and on peak hours.

Figure 8-13 SO_2 and NO_X emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: January 1999 through December 2021[254]



Renewable Energy Output

Wind and Solar Peak Hour Output

The capacity of solar and wind resources are derated from the nameplate or installed capacity value to a level intended to reflect that the resources are a substitute for other capacity resources in the PJM Capacity Market. The derating percentages are intended to reflect expected performance during high load hours and are based on actual historical performance. Figure 8-14 shows the wind and solar output during the top 100 load hours in PJM in 2021. The top 100 load hours in PJM in 2021 are all PJM defined peak load hours. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total capacity committed for each unit, or the ICAP of wind and solar PJM resources derated to 14.7 and 38.0 percent if the unit does not participate in the capacity market.[255] The actual output of the wind and solar resources during the top 100 load hours ranges above and below the derated capacity values. Wind output was above the derated ICAP for 23 hours and below the derated ICAP for 77 hours of the top 100 load

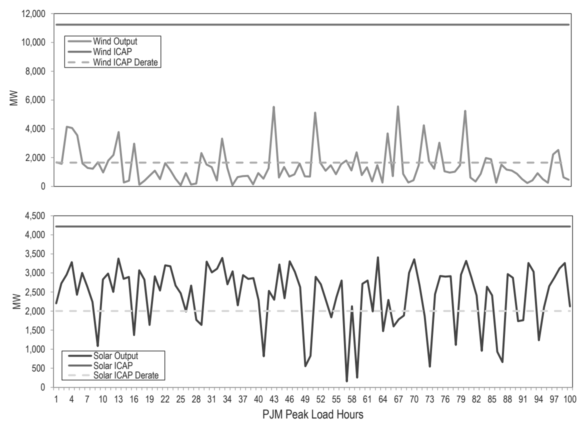
253 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

254 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

255 PJM used derating factors of 13 and 38 percent until June 1, 2017. The current derating factors are 38.0 percent, 42 percent or 60.0 percent depending on installation type. PJM, Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed July 24, 2021).

hours in 2021. The wind capacity factor for the top 100 load hours in 2021 was 12.7 percent. Wind output was above the derated ICAP for 5,276 hours and below the derated ICAP for 3,484 hours in 2021. The wind capacity factor in 2021 was 28.4 percent. Solar output was above the derated ICAP for 74 hours and below the derated ICAP for 26 hours of the top 100 load hours in 2021. The solar capacity factor for the top 100 load hours in 2021 was 57.1 percent. Solar output was above the derated ICAP for 1,951 hours and below the derated ICAP for 6,809 hours in 2021. The solar capacity factor in 2021 was 20.0 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: 2021



Wind Units

Table 8-27 shows the capacity factors of wind units in PJM. In 2021, the capacity factor of wind units in PJM was 28.4 percent. Wind units that were capacity resources had a capacity factor of 28.9 percent and an installed capacity of 9,988.9 MW. Wind units that were energy only had a capacity factor of 24.0 percent and an installed capacity of 1,137.9W. Wind capacity in RPM is derated to 14.7 or 17.6 percent of nameplate capacity for the capacity market, based on the wind farm terrain, and energy only resources are not included in the capacity market.[256]

Table 8-27 Capacity factor of wind units: 2021[257]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	24.0%	1,137.9
Capacity Resource	28.9%	9,988.9
All Units	28.4%	11,126.8

Figure 8-15 shows the average hourly real-time generation of wind units in PJM, by month for 2021. The hour with the highest average output in 2021, 5,008.3 MWh, occurred in March, and the hour with the lowest average output, 942.7 MWh, occurred in August. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-15 Average hourly real-time generation of wind units: 2021

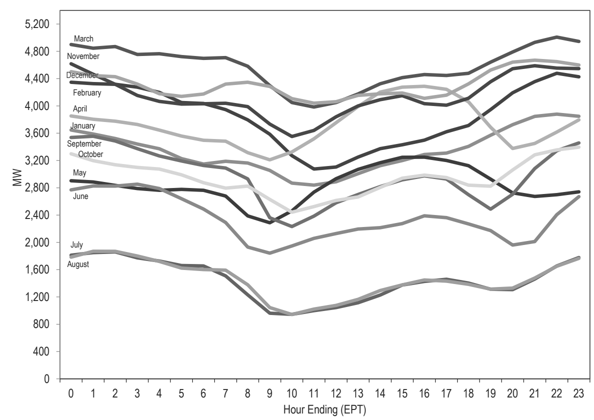


Table 8-28 shows the generation and capacity factor of wind units by month for 2020 and 2021.

Table 8-28 Capacity factor of wind units in PJM by month: 2021

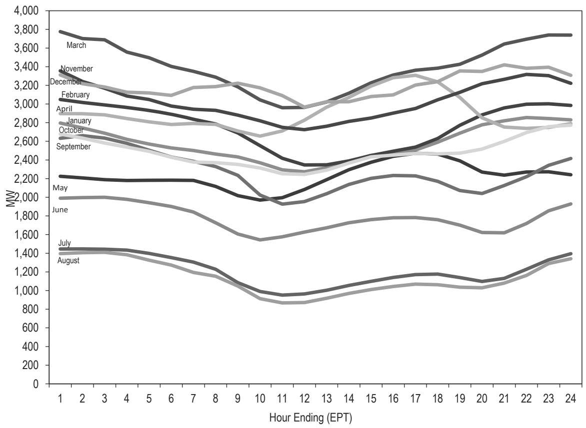
	2020		2021	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,589,612.7	34.7%	2,486,737.9	30.5%
February	2,564,467.7	36.6%	2,595,370.6	34.7%
March	2,739,519.2	36.3%	3,399,080.7	41.1%
April	2,679,800.9	36.5%	2,684,454.5	33.5%
May	2,261,803.9	29.8%	2,110,377.3	25.5%
June	1,662,419.6	22.7%	1,691,536.1	21.1%
July	959,774.9	12.7%	1,073,252.3	13.0%
August	925,896.4	12.2%	1,087,078.7	13.1%
September	1,604,192.1	21.7%	2,137,750.7	26.7%
October	2,322,688.8	30.1%	2,190,071.0	26.4%
November	3,271,878.7	42.7%	2,987,247.7	36.9%
December	2,851,164.6	35.2%	3,208,420.0	38.4%
Annual	26,433,219.4	29.3%	27,651,377.4	28.4%

256 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed July 24, 2021).

257 Capacity factor is calculated based on online date of the resource.

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

Figure 8-16 Average hourly day-ahead generation of wind units: 2021



Output from wind turbines displaces output from other generation types because, in general, wind turbines generate power when the wind is blowing, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output.[258] Figure 8-17 and Table 8-29 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in 2021. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In 2021, the SCED dispatch instruction, or a unit owner reduction in the economic maximum level, for marginal wind resources reduced output for 59.6 percent of the wind unit intervals. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated.

258 The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

Figure 8-17 Marginal fuel at time of wind generation: 2021

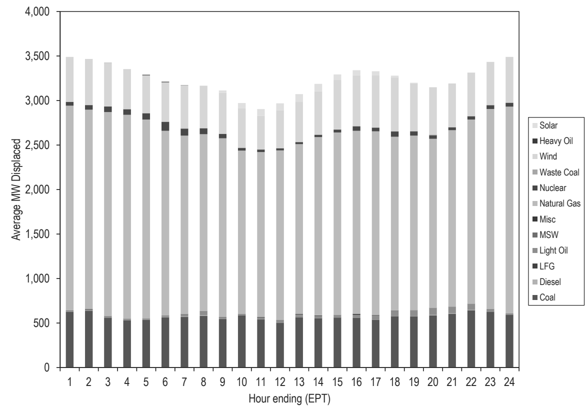


Table 8-29 Marginal fuel MW at time of wind generation: 2021

Hour	Coal	Diesel	LFG	Light Oil	MSW	Misc	Natural Gas	Nuclear	Waste Coal	Wind	Heavy Oil	Solar	Total
0	624.4	0.5	0.6	10.1	2.6	4.9	2,298.2	42.5	3.0	503.4	0.0	0.0	3,490.3
1	638.9	0.2	0.0	12.0	0.6	4.7	2,241.0	50.8	2.9	515.6	0.0	0.0	3,466.7
2	559.1	0.0	1.8	17.0	1.2	1.7	2,289.7	62.2	1.8	490.2	0.7	0.0	3,425.6
3	531.0	0.0	2.1	12.7	2.8	0.6	2,290.2	62.4	3.1	448.1	0.0	0.0	3,352.9
4	534.6	0.5	0.9	14.0	3.2	0.4	2,232.9	70.1	4.3	422.3	6.4	0.0	3,289.5
5	565.5	3.7	0.6	15.6	1.1	1.1	2,071.9	100.7	3.5	441.1	6.4	0.0	3,211.3
6	568.1	3.5	0.0	28.6	0.1	3.2	2,002.6	78.1	5.4	480.6	2.5	0.0	3,172.7
7	582.6	4.6	0.0	48.0	0.5	1.5	1,984.9	64.6	5.4	471.5	0.0	3.9	3,167.6
8	545.3	0.7	0.0	17.2	0.7	3.7	2,008.2	48.5	3.6	459.2	0.0	26.6	3,113.8
9	587.1	0.4	0.1	11.2	0.6	2.4	1,835.6	29.2	4.7	439.9	0.0	60.4	2,971.6
10	539.5	0.0	0.5	19.6	0.1	7.9	1,853.9	27.0	3.8	375.6	0.0	76.0	2,904.0
11	502.0	0.0	0.0	25.9	0.0	5.0	1,906.5	23.1	4.5	423.6	0.0	77.4	2,968.1
12	564.4	0.0	0.6	28.8	1.6	6.6	1,907.9	23.0	2.0	448.6	0.0	88.8	3,072.3
13	554.5	1.0	0.1	24.3	0.0	5.5	2,003.8	24.1	6.7	484.3	0.0	82.5	3,186.8
14	560.9	0.4	0.2	25.3	2.4	3.6	2,048.6	32.4	2.3	555.1	0.0	61.6	3,292.7
15	560.1	0.0	0.0	32.4	0.3	10.9	2,055.6	51.7	1.0	572.3	0.0	56.5	3,340.8
16	536.1	0.5	0.4	48.7	1.4	4.1	2,062.7	41.2	4.0	582.5	0.0	47.1	3,328.8
17	574.3	0.4	2.1	61.3	0.0	3.8	1,951.5	58.2	4.7	597.4	0.2	25.4	3,279.4
18	575.2	1.1	0.9	67.3	0.0	1.4	1,959.9	45.6	6.9	535.9	0.0	5.9	3,200.2
19	585.9	5.5	1.8	76.2	0.1	1.3	1,898.3	41.4	6.2	532.7	0.0	0.0	3,149.6
20	604.7	3.9	1.0	73.4	0.0	2.1	1,981.9	32.0	5.1	487.6	0.0	0.0	3,191.6
21	644.7	2.8	0.0	68.9	0.0	1.0	2,069.0	36.4	5.5	485.2	0.0	0.0	3,313.5
22	627.9	0.6	0.0	28.8	0.0	1.5	2,245.9	43.2	4.2	482.0	0.0	0.0	3,434.1
23	592.4	0.0	2.0	11.3	0.0	1.4	2,324.6	41.6	5.1	511.8	0.0	0.0	3,490.1
Average	573.3	1.3	0.7	32.4	0.8	3.3	2,063.6	47.1	4.2	489.5	0.7	25.5	3,242.3

Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all PJM solar units that are in front of the meter. As shown in Table 8-18, there are 4,791.9 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-19, there are 8,368.8 MW capacity of solar registered in GATS that are not PJM units. Some behind the meter generation exists in clusters, such as community solar farms, and serves dedicated customers. Such customers may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to avoid their proper financial responsibility through badly designed rules, such as rules for netting. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-30 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 20.0 percent in 2021. Solar units that were capacity resources had a capacity factor of 20.4 percent and an installed capacity of 3,634.5 MW. Solar units that were energy only had a capacity factor of 17.2 percent and an installed capacity of 603.8 MW. Solar capacity in RPM is derated to 38.0, 42.0 or 60.0 percent of nameplate capacity for the capacity market, based on the installation type, and energy only resources are not included in the capacity market.[259]

Table 8-30 Capacity factor of solar units: 2021

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	17.2%	603.8
Capacity Resource	20.4%	3,634.5
All Units	20.0%	4,238.3

259 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed July 24, 2019).

Figure 8-18 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output in 2021, 2,957.2 MW, occurred in July, and the hour with the lowest peak average output, 1,306.9 MW, occurred in February. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

Figure 8-18 Average hourly real-time generation of solar units: 2021

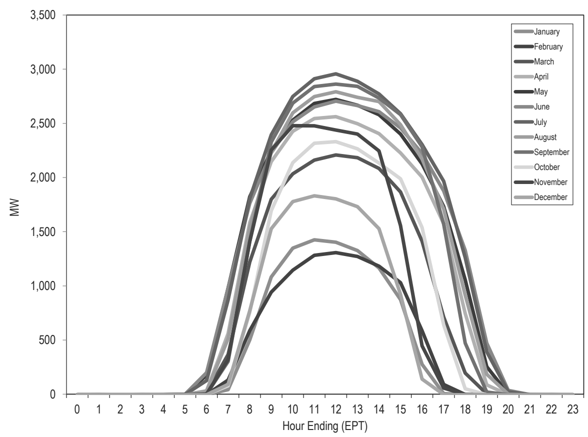


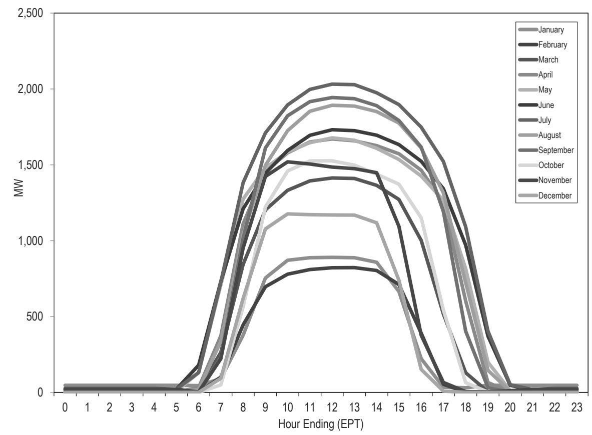
Table 8-31 shows the generation and capacity factor of solar units by month for 2020 and 2021.

Table 8-31 Capacity factor of solar units by month: 2020 and 2021

	2020		2021	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	187,307.7	12.1%	303,578.0	10.6%
February	208,843.2	14.3%	279,267.0	10.4%
March	288,464.5	18.5%	578,735.6	19.4%
April	362,946.3	24.0%	711,376.4	23.8%
May	401,126.5	25.5%	814,711.9	26.1%
June	424,028.5	26.6%	809,575.7	26.8%
July	455,469.5	26.7%	874,340.0	28.0%
August	359,459.6	20.7%	789,824.1	25.2%
September	322,075.7	16.4%	751,990.4	24.1%
October	311,253.5	13.1%	558,541.7	16.6%
November	302,506.9	12.5%	549,543.4	16.8%
December	246,065.0	9.6%	390,712.5	11.3%
Annual	3,869,547.0	17.6%	7,412,196.7	20.0%

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-19 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[260]

Figure 8-19 Average hourly day-ahead generation of solar units: 2021



260 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.

Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2021, PJM was a monthly net exporter of energy in the real-time energy market in all months.[1] In 2021, the real-time net interchange was -37,766.5 GWh. The real-time net interchange in 2020 was -41,630.2 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2021, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In 2021, the total day-ahead net interchange was -25,538.8 GWh. The day-ahead net interchange in 2020 was -15,414.6 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2021, gross imports in the day-ahead energy market were 99.8 percent of gross imports in the real-time energy market (538.7 percent in 2020). In 2021, gross exports in the day-ahead energy market were 73.0 percent of the gross exports in the real-time energy market (104.4 percent in 2020).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2021, there were net scheduled exports at 14 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2021, there were net scheduled exports at six of PJM's nine interface pricing points eligible for real-time transactions in the real-time energy market.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2021, there were net scheduled exports at 15 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2021, there were net scheduled exports at seven of PJM's nine interface pricing points eligible for day-ahead transactions in the day-ahead energy market.[3]
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2021, up to congestion transactions were net exports at three of PJM's nine interface pricing points eligible for day-ahead transactions in the day-ahead energy market.[4]
- **Inadvertent Interchange.** In 2021, net scheduled interchange was -37,767 GWh and net actual interchange was -37,813 GWh, a difference of 47 GWh. In 2020, the difference was 86 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2021, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -1,637 GWh of net scheduled interchange and -10,972 GWh of net actual interchange, a difference of 9,336 GWh. In 2021, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 1,769 GWh of net scheduled interchange and 10,298 GWh of net actual interchange, a difference of 8,529 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2021, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 59.9 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 2021, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 56.6 percent of the hours.

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2 On June 1, 2021, PJM consolidated the SouthIMP and SouthEXP interface pricing points to one new SOUTH interface pricing point. This reduces the number of real-time interface pricing points to eight.

3 On April 15, 2021, PJM retired the Southeast interface pricing point from the day-ahead market. The Southeast interface pricing point can still be assigned to transactions under the VACAR reserve sharing agreement in the real-time market. On June 1, 2021, PJM consolidated the SouthIMP and SouthEXP interface pricing points to one new SOUTH interface pricing point. This reduces the number of day-ahead interface pricing points to seven.

4 Id.

- **Neptune Underwater Transmission Line to Long Island, New York.** In 2021, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 74.8 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2021, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 76.8 percent of the hours.
- **Hudson DC Line.** In 2021, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 69.9 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in 2021, and two such TLRs in 2020.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market decreased by 46.6 percent, from 48,618 bids per day in 2020 to 25,965 bids per day in 2021. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 61.4 percent, from 438,170 MWh per day in 2020, to 169,201 MWh per day in 2021.

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the day-ahead and real-time energy markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SOUTH interface pricing point. (Priority: High. First reported 2013. Status: Partially adopted, Q2 2020.)[5]
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available

5 The grandfathered agreements associated with the Southwest interface pricing point expired in 2012. The Southwest interface pricing point is no longer an eligible pricing point in the day-ahead or real-time energy markets. Effective June 1, 2020, PJM retired the NIPSCO interface pricing point.

to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)

- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features of an energy market including locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features. Pricing in the market areas is transparent and pricing in the nonmarket areas is not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market across the interfaces.

It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. External entities wishing to receive the benefits of the PJM LMP market should join PJM.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. Following the termination of the Northwest pricing point on October 1, 2020, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The MMU continues to recommend the termination of the Southeast interface pricing point and the Ontario interface pricing point. The Southeast pricing point is inappropriately used to support a special agreement and the Ontario interface pricing point is noncontiguous to the PJM footprint that creates opportunities for market participants to engage in sham scheduling activities.

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the real-time or day-ahead energy market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.[6]

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X_1	X_1	X		X_1	X_1	
Spot Import Service		X_2				X_2			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		X
Balancing Operating Reserve	X	X	X						X
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

1 No charge if Point of Delivery is MISO

2 No charge for spot in transmission

6 For an explanation and current rate for each billing line item, see "*Quick Reference Guide to Market Settlements By Type of Business*" (November 1, 2020) <https://pjm.com/markets-and-operations/~/media/0FE1D93C5E61457185BB7652F2F18668.ashx>.

Aggregate Imports and Exports

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for 2020 and 2021. In 2021, gross imports in the day-ahead energy market were 99.8 percent of gross imports in the real-time energy market (538.7 percent in 2020). The large decrease in day-ahead gross imports in 2021 was the result of decreases in up to congestion transactions associated with the new requirement for these transactions to pay uplift charges. In 2021, gross exports in the day-ahead energy market were 73.0 percent of gross exports in the real-time energy market (104.4 percent in 2020).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): 2020 and 2021

Category	2020	2021	Percent Change
Real-Time Gross Imports	6,462.4	7,506.9	16.2%
Real-Time Gross Exports	48,092.6	45,273.5	(5.9%)
Real-Time Net Interchange	(41,630.2)	(37,766.5)	(9.3%)
Day-Ahead Gross Imports	34,815.4	7,491.0	(78.5%)
Day-Ahead Gross Exports	50,230.0	33,029.8	(34.2%)
Day-Ahead Net Interchange	(15,414.6)	(25,538.8)	65.7%
Monthly Average Real-Time Gross Exports	4,007.7	3,772.8	(5.9%)
Monthly Average Real-Time Gross Imports	538.5	625.6	16.2%
Monthly Average Day-Ahead Gross Exports	4,185.8	2,752.5	(34.2%)
Monthly Average Day-Ahead Gross Imports	2,901.3	624.2	(78.5%)

In 2021, PJM was a monthly net exporter of energy in the real-time energy market in all months. In 2021, PJM was a monthly net exporter of energy in the day-ahead energy market in all months (Figure 9-1).[7]

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

Transactions in the day-ahead energy market create financial obligations to deliver in the real-time energy market and to pay operating reserve charges based on differences between the transaction MWh in the day-ahead and real-time energy markets times the applicable operating reserve rates. Up to congestion transactions also create financial obligations to deliver in real time, but did not pay operating reserve charges until November 1, 2020. In 2020, the total day-ahead gross imports and exports were higher than the real-time gross imports and exports, the day-ahead imports net of up to congestion transactions were less than the real-time imports, and the day-ahead exports net of up to congestion transactions were less than real-time exports.

7 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Figure 9-1 Scheduled imports and exports: 2021

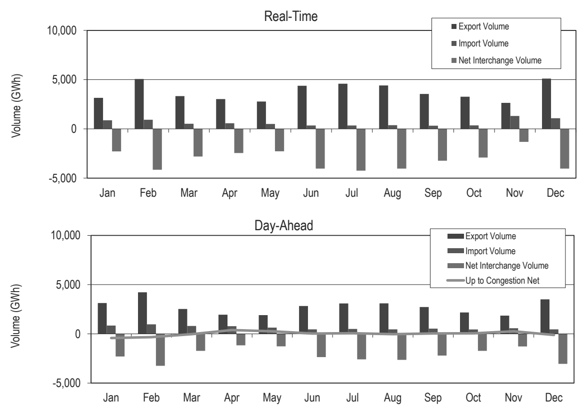
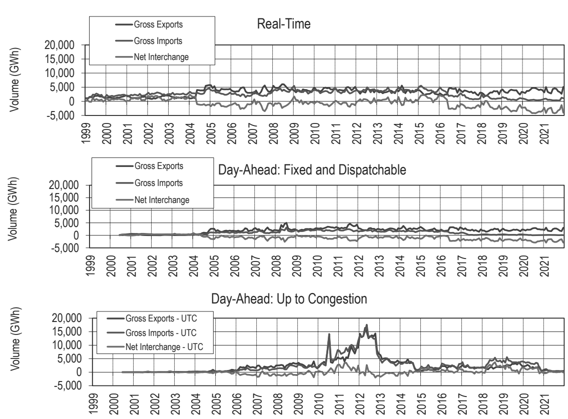


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through December 2021. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the real-time and day-ahead energy markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up to congestion product in September 2010, up to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the day-ahead energy market. On November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. While the gross import and export volumes in the day-ahead energy market decreased, PJM has remained primarily a net exporter in the day-ahead energy market. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a net exporter in the real-time and day-ahead energy markets. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[8] As a result, the volume of import and export up to congestion transactions increased, contributing to PJM becoming a net importer in the day-ahead energy market starting in March 2018. On July 16, 2020, FERC issued an order directing PJM to revise uplift allocation rules to allocate uplift to up to congestion transactions.[9] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. As a result, the volume of up to congestion transactions decreased. In February 2021, winter storms caused significant generation outages in Texas and resulted in power outages across the Electric Reliability Council of Texas (ERCOT) region. These outages occurred between February 10, 2021, and February 27, 2021. During this time, ERCOT imported generation from neighboring regions. While PJM did not have any scheduled exports directly to the ERCOT region, PJM exports during this time increased from an average hourly export of 4,772 MW per hour between February 1 and February 10, 2021, to 7,003 MW per hour between February 10 and February 27, 2021.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through December 31, 2021



8 162 FERC ¶ 61,139.
9 172 FERC ¶ 61,046.

Real-Time Interface Imports and Exports

In the real-time energy market, scheduled imports and exports are defined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. Table 9-19 includes a list of active interfaces in 2021. Figure 9-3 shows the approximate geographic location of the interfaces. In 2021, PJM had 19 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. There are 10 separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-3 through Table 9-5 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the real-time energy market is shown by interface for 2021 in Table 9-3, while gross scheduled imports and exports are shown in Table 9-4 and Table 9-5.

In the real-time energy market, in 2021, there were net scheduled exports at 14 of PJM's 19 interfaces. The top three net exporting interfaces in the real-time energy market accounted for 52.9 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 22.8 percent, PJM/MidAmerican Energy Company (MEC) with 15.6 percent and PJM/NYIS with 14.6 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 35.0 percent of the total net PJM scheduled exports in the real-time energy market. There were net scheduled exports in the real-time energy market at eight of the 10 separate interfaces that connect PJM to MISO. Those eight exporting interfaces represented 62.8 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in 2021, there were net scheduled imports at four of PJM's 19 interfaces. The top importing interface in the real-time energy market was the PJM/Duke Energy Corp. (DUK) interface, which accounted for 82.6 percent of the total net scheduled import volume.[10] The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the real-time energy market. There were net scheduled imports in the real-time energy market at one of the 10 separate interfaces that connect PJM to MISO (Ameren-Illinois (AMIL). This importing interface represented 10.9 percent of the total net PJM scheduled imports in the real-time energy market.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(71.6)	7.3	11.8	(41.0)	125.1	33.1	(14.8)	(48.5)	(39.7)	(56.4)	(72.0)	(16.4)	(183.1)
CPLW	0.3	0.0	0.8	1.0	0.0	0.0	0.0	0.3	1.3	0.0	2.2	12.8	18.7
DUK	180.3	126.0	39.5	164.9	(21.4)	13.7	(10.6)	54.9	(37.4)	2.0	177.2	239.3	928.3
LGEE	(70.3)	(2.9)	(75.6)	(55.9)	(30.9)	(63.9)	(73.9)	(67.2)	(77.6)	(43.7)	(39.6)	(62.1)	(663.7)
MISO	(1,366.6)	(2,572.4)	(2,031.4)	(2,136.6)	(1,758.3)	(2,651.7)	(2,491.9)	(2,184.1)	(1,792.3)	(1,870.3)	(805.3)	(2,656.3)	(24,317.2)
ALTE	(45.6)	(493.6)	(222.7)	(243.6)	(84.9)	(335.5)	(208.6)	(148.5)	(286.5)	(265.1)	(87.1)	(405.0)	(2,826.7)
ALTW	(18.8)	(40.5)	(22.9)	(45.7)	(14.4)	(37.6)	(17.0)	(2.4)	(11.2)	(7.8)	(5.1)	(60.9)	(284.3)
AMIL	(28.4)	(86.5)	(43.2)	(24.6)	(28.7)	(36.5)	(55.3)	(36.7)	(182.3)	(26.0)	387.4	283.6	122.7
CIN	(419.0)	(1,123.5)	(842.1)	(848.8)	(378.3)	(1,068.0)	(1,115.9)	(920.3)	(100.3)	(656.8)	(276.2)	(1,107.1)	(8,856.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(22.3)	(166.0)	(101.3)	(98.8)	(86.5)	(130.6)	(95.7)	(88.3)	(1.3)	(4.5)	(15.0)	(16.8)	(827.2)
MEC	(462.2)	(445.3)	(367.0)	(440.8)	(456.4)	(648.2)	(588.3)	(582.7)	(491.7)	(483.3)	(475.9)	(606.3)	(6,048.2)
MECS	17.7	(126.8)	(396.3)	(399.3)	(335.7)	(340.6)	(345.0)	(366.6)	(359.3)	(387.7)	(89.8)	(356.3)	(3,485.7)
NIPS	(334.6)	(4.8)	0.0	0.0	(340.2)	0.0	(4.6)	0.0	(318.4)	0.0	(287.7)	(346.4)	(1,636.5)
WEC	(53.5)	(85.4)	(35.9)	(35.0)	(33.2)	(54.6)	(61.5)	(38.6)	(41.1)	(39.0)	44.0	(41.3)	(475.1)
NYISO	(1,043.4)	(1,602.5)	(763.5)	(454.4)	(566.1)	(1,260.0)	(1,445.0)	(1,695.3)	(1,264.2)	(910.6)	(858.4)	(1,740.2)	(13,603.7)
HUDS	(212.7)	(354.6)	(150.3)	(57.7)	(55.2)	(264.1)	(290.4)	(356.7)	(333.0)	(256.5)	(166.2)	(367.2)	(2,864.7)
LIND	(226.3)	(211.2)	(191.8)	(108.5)	(163.9)	(202.3)	(196.6)	(204.1)	(198.6)	(192.4)	(173.4)	(223.6)	(2,292.8)
NEPT	(5.3)	(243.3)	(275.1)	(269.5)	(237.3)	(269.7)	(272.0)	(273.5)	(269.4)	(281.0)	(255.0)	(125.9)	(2,777.1)
NYIS	(599.2)	(793.4)	(146.3)	(18.7)	(109.7)	(523.8)	(686.0)	(860.9)	(463.2)	(180.7)	(263.7)	(1,023.5)	(5,669.1)
TVA	89.0	(102.1)	6.9	72.5	(21.1)	(109.7)	(204.5)	(94.1)	(18.6)	(27.1)	272.2	190.6	54.2
Total	(2,282.4)	(4,146.5)	(2,811.5)	(2,449.7)	(2,272.7)	(4,038.4)	(4,240.8)	(4,034.0)	(3,228.6)	(2,906.1)	(1,323.6)	(4,032.3)	(37,766.5)

Table 9-4 Real-time scheduled gross import volume by interface (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	9.3	112.1	101.8	41.7	174.2	85.8	66.4	40.9	16.4	50.7	25.9	18.9	744.2
CPLW	0.3	0.0	0.8	1.0	0.0	0.0	0.0	0.3	1.3	0.0	2.2	12.8	18.7
DUK	237.0	221.9	98.3	188.0	51.1	59.3	72.7	119.4	76.3	83.9	216.0	300.9	1,724.9
LGEE	7.6	84.9	0.9	13.8	13.9	6.4	18.0	29.1	14.5	9.2	7.6	4.9	210.9
MISO	354.2	304.5	142.4	94.1	127.3	51.3	57.8	47.5	88.2	68.8	643.6	411.5	2,391.2
ALTE	135.5	70.4	44.2	33.2	32.2	22.0	10.4	22.3	42.8	25.8	37.9	15.0	491.6
ALTW	0.0	3.8	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.9
AMIL	2.2	13.8	0.0	4.4	7.4	3.4	0.0	0.0	5.4	0.8	390.3	302.0	729.6
CIN	63.7	44.1	31.7	32.7	40.1	2.7	0.9	3.8	7.1	9.0	41.0	8.2	284.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	9.3	19.2	0.5	1.8	6.9	0.6	0.4	0.3	0.0	0.0	0.7	2.6	42.4
MEC	19.5	0.0	18.9	17.6	24.2	12.4	23.9	2.3	8.9	14.6	13.2	8.6	164.2
MECS	123.9	153.2	47.2	1.8	9.9	8.4	22.2	18.9	12.1	12.3	88.0	37.1	534.9
NIPS	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.5	0.8
WEC	0.1	0.0	0.0	2.6	6.6	1.9	0.0	0.0	12.0	6.3	72.2	37.5	139.1
NYISO	123.7	142.3	138.7	117.9	116.8	100.8	112.0	106.3	105.1	121.6	142.8	127.4	1,455.6
HUDS	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.1	0.0	0.0	0.0	0.0	0.9
LIND	0.1	0.0	0.5	2.8	0.4	0.5	0.9	0.1	0.0	0.1	0.3	0.0	5.6
NEPT	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2
NYIS	123.6	142.2	138.3	115.1	116.4	99.6	111.1	106.2	105.1	121.5	142.5	127.3	1,448.9
TVA	138.7	55.4	33.5	115.2	18.9	35.7	17.4	32.4	17.6	21.0	275.7	200.1	961.6
Total	870.8	921.1	516.4	571.6	502.3	339.3	344.3	376.0	319.4	355.3	1,313.9	1,076.5	7,506.9

10 In the real-time energy market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)). CWLP is a balancing authority on the western side of MISO.

Table 9-5 Real-time scheduled gross export volume by interface (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	80.9	104.8	90.1	82.7	49.1	52.7	81.2	89.4	56.1	107.1	97.9	35.3	927.2
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	56.7	95.8	58.8	23.1	72.6	45.6	83.3	64.5	113.8	81.9	38.8	61.6	796.6
LGEE	77.9	87.8	76.5	69.7	44.8	70.3	91.9	96.3	92.1	52.9	47.2	67.0	874.6
MISO	1,720.8	2,876.9	2,173.8	2,230.7	1,885.6	2,702.9	2,549.8	2,231.7	1,880.5	1,939.0	1,448.8	3,067.8	26,708.4
ALTE	181.1	564.0	266.9	276.8	117.1	357.5	219.0	170.8	329.3	290.9	124.9	420.0	3,318.3
ALTW	18.8	44.2	22.9	45.7	14.4	37.6	17.0	2.4	11.2	7.8	5.1	60.9	288.2
AMIL	30.6	100.3	43.2	29.0	36.1	39.9	55.3	36.7	187.7	26.8	2.8	18.4	606.9
CIN	482.6	1,167.6	873.7	881.5	418.4	1,070.7	1,116.8	924.0	107.4	665.8	317.1	1,115.3	9,140.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	31.7	185.2	101.8	100.6	93.4	131.1	96.2	88.5	1.4	4.6	15.7	19.5	869.6
MEC	481.7	445.3	385.9	458.4	480.7	660.6	612.2	585.1	500.6	497.9	489.1	614.9	6,212.3
MECS	106.2	280.0	443.4	401.1	345.6	349.0	367.2	385.5	371.4	400.1	177.8	393.4	4,020.6
NIPS	334.6	4.8	0.0	0.0	340.2	0.0	4.6	0.0	318.4	0.0	288.0	346.8	1,637.3
WEC	53.6	85.4	35.9	37.6	39.8	56.5	61.5	38.6	53.1	45.3	28.3	78.8	614.2
NYISO	1,167.2	1,744.8	902.2	572.3	683.0	1,360.8	1,557.1	1,801.6	1,369.3	1,032.3	1,001.2	1,867.6	15,059.3
HUDS	212.7	354.6	150.3	57.8	55.2	264.8	290.4	356.8	333.0	256.5	166.3	367.3	2,865.6
LIND	226.4	211.2	192.3	111.3	164.3	202.8	197.5	204.3	198.6	192.5	173.7	223.7	2,298.4
NEPT	5.3	243.4	275.1	269.5	237.3	269.7	272.0	273.5	269.4	281.0	255.0	125.9	2,777.3
NYIS	722.8	935.6	284.5	133.8	226.1	623.4	797.2	967.1	568.3	302.2	406.2	1,150.8	7,118.1
TVA	49.7	157.4	26.6	42.7	40.0	145.4	221.8	126.5	36.2	48.1	3.5	9.4	907.4
Total	3,153.2	5,067.6	3,327.9	3,021.3	2,775.0	4,377.7	4,585.1	4,410.0	3,548.0	3,261.4	2,637.5	5,108.8	45,273.5

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[11] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SOUTH interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[12]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[13] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-20 presents the interface pricing points used in 2021. On October 21, 2020, PJM updated the mappings of external balancing authorities to individual pricing points. Figure

11 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

12 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

13 See "Interface Pricing Point Assignment Methodology," (June 1, 2021) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that the balancing authorities in the Western Interconnection are mapped to either the MISO interface pricing point or the SOUTH interface pricing point. This determination was made by PJM based on geographic location rather than the electrical impact on the PJM system. When power is scheduled across a DC tie line, its effects on the PJM system are as if a generator is located at the point in the Eastern Interconnection where the DC tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ based on the relevant DC tie line and could vary from the MISO interface pricing point to the SOUTH interface pricing point. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM rather than geographical location. The MMU recommends that PJM review the mappings of external balancing authority pricing points at least annually to reflect the fact that changes to the system topology can affect the electrical impact of external power sources on PJM.

The MMU has made multiple recommendations to either retire or consolidate interface pricing points used by PJM. The reasons for those recommendations include: pricing points that could no longer be used to price actual transactions; pricing points that were inappropriately used to support special agreements; pricing points that were treated as multiple pricing points when they were a single pricing point; and pricing points that were noncontiguous to the PJM footprint that created opportunities for sham scheduling. Table 9-6 shows the interface pricing points, the recommendation and the date the recommendation was adopted.

Table 9-6 Interface pricing point recommendations and dates adopted[14]

Interface Pricing Point	Recommendation	Date Adopted
Southeast (Real-Time Market)	Retire Pricing Point - Support Special Agreements	
IMO	Retire Pricing Point - Noncontiguous	
SOUTHEXP	Consolidate Pricing Points	6/1/2021
SOUTHIMP	Consolidate Pricing Points	6/1/2021
Southeast	Retire Pricing Point - Support Special Agreements	4/15/2021
Southwest	Retire Pricing Point - Support Special Agreements	4/15/2021
NCMPAEXP	Retire Pricing Point - Preferential Treatment	11/3/2020
NCMPAIMP	Retire Pricing Point - Preferential Treatment	11/3/2020
Northwest	Retire Pricing Point - Noncontiguous	10/1/2020
CPLEEXP	Retire Pricing Point - Preferential Treatment	6/1/2020
CPLEIMP	Retire Pricing Point - Preferential Treatment	6/1/2020
DUKEXP	Retire Pricing Point - Preferential Treatment	6/1/2020
DUKIMP	Retire Pricing Point - Preferential Treatment	6/1/2020
NIPSCO	Retire Pricing Point - Obsolete (Integration into MISO)	6/1/2020
OVEC	Retire Pricing Point - Obsolete (Integration into PJM)	12/1/2018

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[15] The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions.

The contract transmission path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag.

In the real-time energy market, in 2021, there were net scheduled exports at six of PJM's nine interface pricing points eligible for real-time transactions.[16] The top three net exporting interface pricing points in the real-time energy market accounted for 83.4 percent of the total net scheduled exports: PJM/MISO with 62.3 percent, PJM/NYIS with 14.0 percent and PJM/HUDSONTP with 7.1 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the

14 The Southeast interface pricing point was retired from the day-ahead market only. This pricing point can still be assigned to transactions under the VACAR reserve sharing agreement.
15 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.
16 On June 1, 2021, PJM consolidated the SouthIMP and SouthEXP interface pricing points to one new SOUTH interface pricing point. This reduces the number of real-time and day-ahead interface pricing points to eight.

NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 33.6 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in 2021, there were net scheduled imports at three of PJM's nine interface pricing points eligible for real-time transactions. The top importing interface pricing point in the real-time energy market was the PJM/SouthIMP interface pricing point, which accounted for 63.0 percent of the total net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the real-time energy market.[17]

Table 9-7 Real-time scheduled net interchange volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	152.7	219.7	46.9	1.4	13.4	(11.6)	(56.5)	(53.7)	10.8	18.4	38.7	33.3	413.3
MISO	(1,514.5)	(2,527.6)	(2,077.8)	(2,144.9)	(1,781.6)	(2,597.0)	(2,409.0)	(2,116.6)	(1,804.9)	(1,888.4)	(1,386.0)	(3,036.0)	(25,284.1)
NYISO	(1,043.6)	(1,619.0)	(763.5)	(454.4)	(566.1)	(1,259.7)	(1,444.8)	(1,692.0)	(1,265.4)	(910.6)	(858.3)	(1,740.2)	(13,617.7)
HUDSONTP	(212.7)	(354.6)	(150.3)	(57.7)	(55.2)	(264.1)	(290.4)	(356.7)	(333.0)	(256.5)	(166.2)	(367.2)	(2,864.7)
LINDENVFT	(226.3)	(211.2)	(191.8)	(108.5)	(163.9)	(202.3)	(196.6)	(204.1)	(198.6)	(192.4)	(173.4)	(223.6)	(2,292.8)
NEPTUNE	(5.3)	(243.3)	(275.1)	(269.5)	(237.3)	(269.7)	(272.0)	(273.5)	(269.4)	(281.0)	(255.0)	(125.9)	(2,777.1)
NYIS	(599.4)	(809.9)	(146.3)	(18.7)	(109.7)	(523.6)	(685.8)	(857.6)	(464.4)	(180.6)	(263.6)	(1,023.5)	(5,683.1)
Southern Imports	395.2	488.0	237.7	370.3	278.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,769.2
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	395.2	488.0	237.7	370.3	278.0								1,769.2
Southern Exports	(272.1)	(707.5)	(254.8)	(222.2)	(216.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,673.0)
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(272.1)	(707.5)	(254.8)	(222.2)	(216.3)								(1,673.0)
SOUTH						(170.1)	(330.5)	(171.8)	(169.1)	(125.5)	882.1	710.6	625.8
Total	(2,282.4)	(4,146.5)	(2,811.5)	(2,449.7)	(2,272.7)	(4,038.4)	(4,240.8)	(4,034.0)	(3,228.6)	(2,906.1)	(1,323.6)	(4,032.3)	(37,766.5)

Table 9-8 Real-time scheduled gross import volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	152.7	219.7	47.0	1.4	13.4	11.0	23.5	25.2	15.6	20.7	40.8	34.4	605.2
MISO	199.4	87.6	93.0	82.0	94.1	34.8	34.3	22.1	50.1	30.9	57.6	26.7	812.7
NYISO	123.5	125.8	138.7	117.9	116.8	100.3	112.0	106.1	103.6	121.6	142.8	127.4	1,436.6
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.1	0.0	0.0	0.0	0.0	0.9
LINDENVFT	0.1	0.0	0.5	2.8	0.4	0.5	0.9	0.1	0.0	0.1	0.3	0.0	5.6
NEPTUNE	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2
NYIS	123.4	125.7	138.3	115.1	116.4	99.1	111.1	105.9	103.6	121.5	142.5	127.3	1,430.0
Southern Imports	395.2	488.0	237.7	370.3	278.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,769.2
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	395.2	488.0	237.7	370.3	278.0								1,769.2
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0								0.0
SOUTH						193.2	174.5	222.6	150.1	182.0	1,072.8	888.1	2,883.2
Total	870.8	921.1	516.4	571.6	502.3	339.3	344.3	376.0	319.4	355.3	1,313.9	1,076.5	7,506.9

Table 9-9 Real-time scheduled gross export volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	0.0	0.0	0.1	0.0	0.0	22.6	80.0	78.9	4.8	2.4	2.1	1.1	191.9
MISO	1,713.9	2,615.2	2,170.8	2,226.8	1,875.7	2,631.7	2,443.3	2,138.7	1,855.0	1,919.3	1,443.6	3,062.6	26,096.8
NYISO	1,167.2	1,744.8	902.2	572.3	683.0	1,360.0	1,556.8	1,798.1	1,369.0	1,032.2	1,001.1	1,867.6	15,054.3
HUDSONTP	212.7	354.6	150.3	57.8	55.2	264.8	290.4	356.8	333.0	256.5	166.3	367.3	2,865.6
LINDENVFT	226.4	211.2	192.3	111.3	164.3	202.8	197.5	204.3	198.6	192.5	173.7	223.7	2,298.4
NEPTUNE	5.3	243.4	275.1	269.5	237.3	269.7	272.0	273.5	269.4	281.0	255.0	125.9	2,777.3
NYIS	722.8	935.6	284.5	133.8	226.1	622.7	796.9	963.6	568.0	302.2	406.1	1,150.8	7,113.1
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0								0.0
Southern Exports	272.1	707.5	254.8	222.2	216.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,673.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	272.1	707.5	254.8	222.2	216.3								1,673.0
SOUTH						363.3	505.0	394.4	319.2	307.5	190.7	177.5	2,257.4
Total	3,153.2	5,067.6	3,327.9	3,021.3	2,775.0	4,377.7	4,585.1	4,410.0	3,548.0	3,261.4	2,637.5	5,108.8	45,273.5

17 In the real-time energy market, one PJM interface pricing points had a net interchange of zero (Southeast).

Day-Ahead Interface Imports and Exports

In the day-ahead energy market, as in the real-time energy market, scheduled imports and exports are determined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the day-ahead energy market requires fewer steps than in the real-time energy market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the real-time energy market.[18] Day-ahead energy market schedules need to be cleared through the day-ahead energy market process in order to become an approved schedule. The day-ahead energy market transactions are financially binding, but will not physically flow unless they are also submitted in the real-time energy market. In the day-ahead energy market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up to congestion; and dispatchable.[19]

In the day-ahead energy market, transaction sources and sinks are determined solely by market participants. In Table 9-10, Table 9-11, and Table 9-12, the scheduled interface designation is determined by the transmission reservation that was acquired and associated with the day-ahead market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SOUTH as the import pricing point when submitting the transaction in the day-ahead energy market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled interface pricing point tables, the import transaction would appear as scheduled through the SOUTH interface pricing point, which reflects the expected power flow.

Table 9-10 through Table 9-12 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the day-ahead energy market is shown by interface for 2021 in Table 9-10, while gross scheduled imports and exports are shown in Table 9-11 and Table 9-12.

In the day-ahead energy market, in 2021, there were net scheduled exports at 15 of PJM's 19 interfaces. The top three net exporting interfaces in the day-ahead energy market accounted for 58.7 percent of the total net scheduled exports: PJM/NYIS with 22.7 percent, PJM/MidAmerican Energy Company (MEC) with 21.8 percent and PJM/Cinergy (CIN) with 14.2 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 40.6 percent of the total net PJM scheduled exports in the day-ahead energy market. In 2021, there were net exports in the day-ahead energy market at nine of the 10 separate interfaces that connect PJM to MISO. Those nine interfaces represented 54.1 percent of the total net PJM exports in the day-ahead energy market.

In the day-ahead energy market, in 2021, there were net scheduled imports at two of PJM's 19 interfaces. The top importing interface in the day-ahead energy market was

18 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.
19 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

the PJM/Duke Energy Corp. (DUK) interface, which accounted for 99.5 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the day-ahead energy market. In 2021, there were no net imports in the day-ahead energy market at any of the 10 separate interfaces that connect PJM to MISO.[20]

Table 9-10 Day-ahead scheduled net interchange volume by interface (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(61.9)	(86.3)	(51.5)	(74.5)	80.0	13.2	(10.8)	(41.4)	(38.4)	(12.1)	(35.8)	(30.4)	(350.0)
CPLW	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.1
DUK	47.6	28.7	21.3	53.5	(9.0)	(0.5)	7.0	34.4	3.2	23.7	18.6	5.2	233.8
LGEE	(74.7)	(91.9)	(79.8)	(67.4)	(46.3)	(65.6)	(98.3)	(96.3)	(82.6)	(39.9)	(24.6)	(53.3)	(820.8)
MISO	(1,016.7)	(1,386.7)	(1,022.2)	(1,105.8)	(1,130.0)	(1,396.9)	(1,267.3)	(1,077.3)	(1,166.3)	(1,067.3)	(879.2)	(1,536.7)	(14,052.4)
ALTE	(69.6)	(363.9)	(151.9)	(126.2)	(59.2)	(286.7)	(161.7)	(114.9)	(237.4)	(92.3)	(42.8)	(299.7)	(2,006.1)
ALTW	(17.4)	(25.7)	(10.6)	(42.1)	(10.2)	(40.0)	(14.5)	(2.1)	(10.6)	(10.1)	(4.5)	(48.5)	(236.2)
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	(10.0)	(10.1)	(9.6)	(2.0)	(0.0)	(11.6)	(43.3)
CIN	(103.1)	(475.7)	(463.4)	(437.6)	(36.9)	(492.7)	(499.6)	(427.6)	(53.6)	(407.2)	(49.2)	(237.6)	(3,684.2)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.0)
MEC	(481.6)	(438.3)	(383.8)	(458.2)	(480.8)	(473.3)	(497.3)	(491.6)	(474.2)	(495.1)	(481.4)	(497.7)	(5,653.3)
MECS	39.2	(21.4)	16.1	(11.5)	(170.0)	(50.4)	(26.3)	1.3	(15.6)	(25.3)	2.3	(27.6)	(289.3)
NIPS	(334.4)	(4.8)	0.0	0.0	(340.2)	0.0	(4.8)	0.0	(322.7)	0.0	(288.4)	(339.6)	(1,634.8)
WEC	(49.9)	(56.9)	(28.5)	(30.3)	(32.7)	(53.8)	(53.0)	(32.4)	(42.8)	(35.2)	(15.2)	(74.5)	(505.2)
NYISO	(754.4)	(1,326.6)	(563.5)	(369.4)	(413.3)	(915.9)	(1,220.1)	(1,395.2)	(959.3)	(661.1)	(643.5)	(1,312.3)	(10,534.6)
HUDS	(79.7)	(210.9)	(80.5)	0.0	(7.3)	(158.7)	(232.2)	(248.8)	(227.3)	(148.1)	(109.1)	(290.7)	(1,793.2)
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	(10.7)	(249.4)	(285.2)	(285.6)	(237.9)	(276.5)	(276.2)	(285.7)	(275.7)	(285.7)	(256.2)	(127.0)	(2,851.9)
NYIS	(663.9)	(866.4)	(197.8)	(83.8)	(168.0)	(480.8)	(711.7)	(860.8)	(456.3)	(227.3)	(278.2)	(894.6)	(5,889.5)
TVA	(10.9)	(52.6)	(4.9)	8.2	(8.4)	(32.8)	(62.4)	(37.3)	(4.9)	(14.5)	18.5	0.3	(201.9)
Total without Up To Congestion	(1,871.0)	(2,915.4)	(1,699.9)	(1,555.4)	(1,526.9)	(2,398.6)	(2,651.9)	(2,613.1)	(2,248.3)	(1,771.2)	(1,546.1)	(2,927.0)	(25,724.8)
Up To Congestion	(421.3)	(332.8)	(27.7)	387.7	260.9	36.6	63.6	(28.7)	45.9	49.3	267.0	(114.4)	186.0
Total	(2,292.3)	(3,248.1)	(1,727.6)	(1,167.7)	(1,266.0)	(2,362.0)	(2,588.3)	(2,641.9)	(2,202.4)	(1,721.9)	(1,279.1)	(3,041.4)	(25,538.8)

Table 9-11 Day-ahead scheduled gross import volume by interface (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	2.4	4.6	18.4	3.2	121.9	59.6	46.1	16.7	11.7	21.8	0.8	0.4	307.7
CPLW	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.1
DUK	55.8	43.8	32.7	54.8	5.6	10.2	26.2	39.6	32.7	28.0	30.4	27.0	386.7
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	187.8	107.6	95.5	62.2	19.7	23.4	20.9	22.5	32.5	17.5	53.1	36.7	679.3
ALTE	102.1	46.0	52.2	55.8	14.4	21.2	10.4	16.6	25.6	17.1	29.4	10.6	401.2
ALTW	0.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	40.4	26.0	8.6	6.0	4.6	1.2	0.0	0.0	0.0	0.0	5.7	0.0	92.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MECS	45.4	33.0	34.7	0.4	0.8	1.0	10.5	5.9	6.9	0.1	16.0	25.9	180.4
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.9	0.3	2.6
NYISO	0.0	0.4	5.4	0.7	3.1	0.4	0.4	0.5	0.9	4.3	11.5	8.4	35.9
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	0.0	0.4	5.4	0.7	3.1	0.4	0.4	0.5	0.9	4.3	11.5	8.4	35.9
TVA	6.0	7.0	0.0	25.6	0.6	1.1	0.0	0.0	0.0	0.4	21.4	0.8	62.9
Total without Up To Congestion	251.9	163.3	152.7	146.5	150.9	94.7	93.6	79.3	77.7	72.1	117.2	73.7	1,473.6
Up To Congestion	590.6	809.5	654.2	637.6	488.6	369.8	405.9	384.2	450.4	380.0	459.8	386.8	6,017.4
Total	842.5	972.7	806.9	784.2	639.6	464.5	499.5	463.4	528.1	452.1	577.0	460.5	7,491.0

20 In the day-ahead energy market, two PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/Linden (LIND)).

Table 9-12 Day-ahead scheduled gross export volume by interface (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	64.3	90.8	69.9	77.7	41.9	46.4	56.9	58.1	50.0	34.0	36.6	30.8	657.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	8.1	15.1	11.4	1.3	14.6	10.7	19.2	5.2	29.4	4.3	11.7	21.8	152.9
LGEE	74.7	91.9	79.8	67.4	46.3	65.6	98.3	96.3	82.6	39.9	24.6	53.3	820.8
MISO	1,204.5	1,494.2	1,117.7	1,168.0	1,149.7	1,420.3	1,288.1	1,099.7	1,198.8	1,084.8	932.4	1,573.4	14,731.7
ALTE	171.6	409.8	204.1	181.9	73.5	307.9	172.1	131.5	262.9	109.4	72.2	310.2	2,407.2
ALTW	17.4	28.3	10.6	42.1	10.2	40.0	14.5	2.1	10.6	10.1	4.5	48.5	238.8
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	10.0	10.1	9.6	2.0	0.0	11.6	43.3
CIN	143.4	501.7	472.0	443.6	41.5	493.9	499.6	427.6	53.6	407.2	55.0	237.6	3,776.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	481.6	438.3	383.8	458.2	480.8	473.3	497.3	491.6	474.2	495.1	481.4	497.7	5,653.3
MECS	6.2	54.4	18.6	11.9	170.7	51.4	36.8	4.6	22.5	25.4	13.8	53.5	469.7
NIPS	334.4	4.8	0.0	0.0	340.2	0.0	4.8	0.0	322.7	0.0	288.4	339.6	1,634.8
WEC	49.9	56.9	28.5	30.3	32.7	53.8	53.0	32.4	42.8	35.6	17.1	74.8	507.8
NYISO	754.4	1,326.9	568.8	370.2	416.3	916.3	1,220.5	1,395.7	960.2	665.4	655.0	1,320.8	10,570.5
HUDS	79.7	210.9	80.5	0.0	7.3	158.7	232.2	248.8	227.3	148.1	109.1	290.7	1,793.2
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	10.7	249.4	285.2	285.6	237.9	276.5	276.2	285.7	275.7	285.7	256.2	127.0	2,851.9
NYIS	663.9	866.7	203.1	84.5	171.1	481.1	712.1	861.3	457.2	231.6	289.7	903.0	5,925.4
TVA	16.9	59.6	4.9	17.4	9.0	33.9	62.4	37.3	4.9	14.9	3.0	0.5	264.8
Total without Up To Congestion	2,123.0	3,078.6	1,852.6	1,701.9	1,677.8	2,493.3	2,745.5	2,692.4	2,326.0	1,843.3	1,663.3	3,000.7	27,198.4
Up To Congestion	1,011.9	1,142.2	681.9	250.0	227.7	333.2	342.3	412.9	404.5	330.8	192.8	501.2	5,831.4
Total	3,134.9	4,220.9	2,534.4	1,951.9	1,905.5	2,826.5	3,087.8	3,105.3	2,730.5	2,174.1	1,856.1	3,501.9	33,029.8

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-13 through Table 9-18 show the day-ahead scheduled interchange totals at the interface pricing points. In 2021, up to congestion transactions accounted for 80.3 percent of all scheduled import MW transactions and 17.7 percent of all scheduled export MW transactions in the day-ahead energy market. The day-ahead net scheduled interchange in 2021, including up to congestion transactions, is shown by interface pricing point in Table 9-13. Scheduled up to congestion transactions by interface pricing point in 2021 are shown in Table 9-14. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-15 and Table 9-17, while gross scheduled import and export up to congestion transactions are shown in Table 9-16 and Table 9-18.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface pricing point with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006. At that time, the real-time Southeast and Southwest interface pricing points remained only to support certain grandfathered agreements with specific generating units and to price energy under the reserve sharing agreement with VACAR. The reserve sharing agreement allows for the transfer of energy during emergencies. Interchange transactions created as part of the reserve sharing agreement are currently settled at the Southeast interface price. PJM also kept the day-ahead Southeast and Southwest interface pricing points to facilitate long-term day-ahead positions that were entered prior to the consolidation.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the Southeast and Southwest interface pricing points from the day-ahead and real-time energy markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SOUTH interface pricing point.[21] PJM should immediately eliminate interface pricing points when changes to the market mean that the pricing points can no longer be used to price actual transactions and do not reflect actual price formation.

In the day-ahead energy market, in 2021, there were net scheduled exports at seven of PJM's nine interface pricing

21 The grandfathered agreements associated with the Southwest interface pricing point expired in 2012. The Southwest interface pricing point is no longer an eligible pricing point in the day-ahead or real-time energy markets.

points eligible for day-ahead transactions.[22] The top three net exporting interface pricing points in the day-ahead energy market accounted for 84.7 percent of the total net scheduled exports: PJM/MISO with 48.1 percent, PJM/NYIS with 26.3 percent and PJM/NEPTUNE with 10.3 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 46.6 percent of the total net PJM scheduled exports in the day-ahead energy market. However, the PJM/LINDENVFT interface pricing point had net scheduled imports in the day-ahead energy market.

In the day-ahead energy market, in 2021, there were net scheduled imports at three of PJM's nine interface pricing points eligible for day-ahead transactions. The top importing interface pricing point in the day-ahead energy market was the PJM/SouthIMP interface pricing point, which accounted for 78.5 percent of the total net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 9.9 percent of the total net PJM scheduled imports in the day-ahead energy market. However, the PJM/NYIS, PJM/NEPTUNE and PJM/HUDSONTP interface pricing points had net scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in 2021, up to congestion transactions had net scheduled exports at three of PJM's nine interface pricing points eligible for day-ahead transactions.[23] The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 90.8 percent of the total net up to congestion scheduled exports: PJM/NYIS with 53.0 percent and PJM/HUDSONTP with 37.8 percent of the net up to congestion scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 80.8 percent of the total net scheduled up to congestion exports in the day-ahead energy market. However, the PJM/LINDENVFT and PJM/NEPTUNE interface pricing points had net up to congestion scheduled imports in the day-ahead energy market.

In the day-ahead energy market, in 2021, up to congestion transactions had net scheduled imports at six of PJM's nine interface pricing points eligible for day-ahead transactions. The top two importing interface pricing points eligible for up to congestion transactions accounted for 80.5 percent of the total up to congestion scheduled imports: PJM/SouthIMP with 41.5 percent and PJM/MISO with 39.0 percent of the net up to congestion scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 7.9 percent of the total net scheduled up to congestion imports in the day-ahead energy market. However, the PJM/HUDSONTP and PJM/NYIS interface pricing points had net up to congestion scheduled exports in the day-ahead energy market.[24]

Table 9-13 Day-ahead scheduled net interchange volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	55.3	(17.0)	(20.3)	25.0	34.4	52.4	19.7	(9.3)	27.4	(32.6)	48.8	36.7	220.6
MISO	(1,410.2)	(1,951.1)	(821.9)	(755.7)	(889.6)	(1,342.9)	(1,237.3)	(932.5)	(922.5)	(872.5)	(638.9)	(1,434.5)	(13,209.4)
NYISO	(990.5)	(1,597.1)	(812.8)	(442.8)	(497.4)	(1,053.4)	(1,273.4)	(1,614.1)	(1,168.1)	(784.6)	(732.6)	(1,618.7)	(12,585.4)
HUDSONTP	(207.5)	(293.2)	(232.4)	(64.1)	(76.7)	(217.1)	(289.2)	(313.2)	(330.7)	(219.2)	(142.4)	(349.4)	(2,735.3)
LINDENVFT	51.2	18.8	5.8	(15.7)	(12.7)	6.2	54.4	47.7	20.0	14.5	18.0	(19.0)	189.2
NEPTUNE	(11.3)	(256.4)	(280.0)	(280.0)	(245.6)	(278.1)	(274.6)	(272.5)	(268.3)	(274.8)	(258.3)	(130.0)	(2,829.9)
NYIS	(822.9)	(1,066.4)	(306.2)	(82.9)	(162.4)	(564.4)	(764.0)	(1,076.1)	(589.0)	(305.1)	(349.9)	(1,120.2)	(7,209.4)
Southern Imports	239.9	635.7	145.5	225.8	246.2								1,493.1
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHIMP	239.9	635.7	145.5	225.8	246.2								1,493.1
Southern Exports	(186.9)	(318.6)	(218.1)	(220.1)	(159.5)								(1,103.2)
SOUTHEAST	0.0	(4.3)	(1.0)	(3.8)	0.0								(9.1)
SOUTHEXP	(186.9)	(314.3)	(217.1)	(216.3)	(159.5)								(1,094.1)
SOUTH						(18.1)	(97.3)	(86.0)	(139.2)	(32.3)	43.6	(25.1)	(354.5)
Total	(2,292.3)	(3,248.1)	(1,727.6)	(1,167.7)	(1,266.0)	(2,362.0)	(2,588.3)	(2,641.9)	(2,202.4)	(1,721.9)	(1,279.1)	(3,041.4)	(25,538.8)

22 On April 15, 2021, PJM retired the Southeast interface pricing point from the day-ahead market. The Southeast interface pricing point can still be assigned to transactions under the VACAR reserve sharing agreement in the Real-Time Market. On June 1, 2021, PJM consolidated the SouthIMP and SouthEXP interface pricing points to one new SOUTH interface pricing point. This reduces the number of day-ahead interface pricing points to seven.

23 On April 15, 2021, PJM retired the Southeast interface pricing point from the day-ahead market. The Southeast interface pricing point can still be assigned to transactions under the VACAR reserve sharing agreement in the Real-Time Market. On June 1, 2021, PJM consolidated the SouthIMP and SouthEXP interface pricing points to one new SOUTH interface pricing point. This reduces the number of day-ahead interface pricing points to seven.

24 In the day-ahead energy market, one PJM interface pricing point had up to congestion net interchange of zero (Southeast).

Table 9-14 Up to congestion scheduled net interchange volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	(1.3)	(71.1)	(54.8)	25.0	33.9	50.2	9.3	(14.4)	20.4	(32.6)	33.2	10.9	8.7
MISO	(336.7)	(521.5)	234.9	350.1	240.9	53.8	39.6	149.9	249.8	195.2	257.8	129.6	1,043.3
NYISO	(236.2)	(270.6)	(249.3)	(73.3)	(84.2)	(135.1)	(53.3)	(218.8)	(208.6)	(123.5)	(89.1)	(307.5)	(2,049.6)
HUDSONTP	(127.8)	(84.7)	(152.0)	(64.1)	(69.4)	(56.0)	(54.8)	(64.5)	(103.4)	(71.1)	(33.3)	(59.9)	(941.0)
LINDENVFT	51.2	18.8	5.8	(15.7)	(12.7)	6.2	54.4	47.7	20.0	23.7	18.0	(19.0)	198.5
NEPTUNE	(0.6)	(7.1)	5.3	5.6	(7.6)	(1.7)	1.6	13.2	7.4	1.7	(2.1)	(3.0)	12.7
NYIS	(159.1)	(197.6)	(108.4)	0.8	5.6	(83.7)	(54.5)	(215.3)	(132.6)	(77.8)	(71.6)	(225.6)	(1,319.8)
Southern Imports	175.8	580.3	93.7	142.2	118.0								1,110.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHIMP	175.8	580.3	93.7	142.2	118.0								1,110.0
Southern Exports	(22.8)	(50.0)	(52.1)	(56.3)	(47.8)								(228.9)
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHEXP	(22.8)	(50.0)	(52.1)	(56.3)	(47.8)								(228.9)
SOUTH						67.7	68.0	54.6	(15.6)	10.2	65.0	52.6	302.5
Total Interfaces	(421.3)	(332.8)	(27.7)	387.7	260.9	36.6	63.6	(28.7)	45.9	49.3	267.0	(114.4)	186.0
INTERNAL	3,896.8	5,150.6	5,248.0	4,060.0	4,519.9	4,488.2	4,336.0	3,255.2	3,992.3	3,375.1	4,281.0	4,111.8	50,714.7
Total	3,475.6	4,817.8	5,220.3	4,447.6	4,780.9	4,524.8	4,399.5	3,226.5	4,038.3	3,424.3	4,547.9	3,997.3	50,900.7

Table 9-15 Day-ahead scheduled gross import volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	74.2	76.0	56.2	35.8	43.6	65.3	38.5	17.8	39.9	17.1	64.3	43.2	572.0
MISO	416.1	208.0	521.5	470.7	293.6	198.8	159.0	207.2	335.4	286.7	315.9	264.0	3,677.2
NYISO	112.3	53.0	83.7	51.8	56.1	58.9	108.7	107.5	79.0	61.7	57.5	33.9	864.1
HUDSONTP	15.8	8.5	6.0	7.6	11.6	6.5	11.6	13.9	8.5	4.6	4.7	2.4	101.8
LINDENVFT	61.1	30.1	44.2	4.5	10.1	24.7	63.3	61.9	37.8	41.7	24.0	13.2	416.7
NEPTUNE	0.0	6.2	14.5	20.0	9.5	16.6	12.6	22.7	18.6	5.7	6.0	2.1	134.6
NYIS	35.4	8.1	19.0	19.6	24.9	11.1	21.1	9.0	14.0	9.7	22.7	16.3	211.0
Southern Imports	239.9	635.7	145.5	225.8	246.2								1,493.1
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHIMP	239.9	635.7	145.5	225.8	246.2								1,493.1
Southern Exports	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0								0.0
SOUTH						141.4	193.3	131.0	73.8	86.5	139.2	119.3	884.6
Total	842.5	972.7	806.9	784.2	639.6	464.5	499.5	463.4	528.1	452.1	577.0	460.5	7,491.0

Table 9-16 Up to congestion scheduled gross import volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	17.5	20.1	21.7	35.8	43.1	63.1	28.1	11.9	32.8	17.1	48.8	17.4	357.3
MISO	285.0	156.4	460.5	408.5	274.4	177.6	148.6	190.6	309.9	269.6	280.3	253.5	3,214.9
NYISO	112.3	52.7	78.3	51.1	53.1	58.6	108.2	107.0	78.3	57.4	46.0	25.5	828.4
HUDSONTP	15.8	8.5	6.0	7.6	11.6	6.5	11.6	13.9	8.5	4.6	4.7	2.4	101.8
LINDENVFT	61.1	30.1	44.2	4.5	10.1	24.7	63.3	61.9	37.8	41.7	24.0	13.2	416.7
NEPTUNE	0.0	6.2	14.5	20.0	9.5	16.6	12.6	22.7	18.6	5.7	6.0	2.1	134.6
NYIS	35.4	7.8	13.6	18.9	21.8	10.8	20.7	8.5	13.3	5.3	11.3	7.9	175.3
Southern Imports	175.8	580.3	93.7	142.2	118.0								1,110.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHIMP	175.8	580.3	93.7	142.2	118.0								1,110.0
Southern Exports	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0								0.0
SOUTH	0.0	0.0	0.0	0.0	0.0	70.5	121.0	74.7	29.5	35.9	84.7	90.5	506.7
Total Interfaces	590.6	809.5	654.2	637.6	488.6	369.8	405.9	384.2	450.4	380.0	459.8	386.8	6,017.4

Table 9-17 Day-ahead scheduled gross export volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	18.9	93.1	76.5	10.8	9.2	12.9	18.8	27.1	12.4	49.7	15.6	6.5	351.4
MISO	1,826.3	2,159.1	1,343.4	1,226.4	1,183.2	1,541.8	1,396.3	1,139.7	1,257.9	1,159.2	954.8	1,698.5	16,886.6
NYISO	1,102.8	1,650.1	896.5	494.6	553.5	1,112.3	1,382.1	1,721.6	1,247.1	846.3	790.0	1,652.6	13,449.6
HUDSONTP	223.3	301.7	238.5	71.7	88.4	223.6	300.8	327.1	339.2	223.9	147.2	351.8	2,837.1
LINDENVFT	9.9	11.3	38.4	20.3	22.8	18.4	9.0	14.2	17.9	27.2	6.0	32.2	227.5
NEPTUNE	11.3	262.7	294.5	300.0	255.1	294.7	287.2	295.2	287.0	280.5	264.3	132.1	2,964.6
NYIS	858.3	1,074.5	325.2	102.5	187.3	575.6	785.1	1,085.1	603.0	314.8	372.6	1,136.5	7,420.4
Southern Imports	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0								0.0
Southern Exports	186.9	318.6	218.1	220.1	159.5								1,103.2
SOUTHEAST	0.0	4.3	1.0	3.8	0.0								9.1
SOUTHEXP	186.9	314.3	217.1	216.3	159.5								1,094.1
SOUTH						159.5	290.7	217.0	213.0	118.8	95.7	144.3	1,239.0
Total	3,134.9	4,220.9	2,534.4	1,951.9	1,905.5	2,826.5	3,087.8	3,105.3	2,730.5	2,174.1	1,856.1	3,501.9	33,029.8

Table 9-18 Up to congestion scheduled gross export volume by interface pricing point (GWh): 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	18.8	91.1	76.5	10.8	9.2	12.9	18.8	26.3	12.4	49.7	15.6	6.5	348.6
MISO	621.8	677.9	225.7	58.4	33.5	123.8	109.0	40.7	60.1	74.4	22.4	123.9	2,171.7
NYISO	348.6	323.2	327.7	124.4	137.2	193.7	161.6	325.8	286.9	180.9	135.1	333.0	2,878.0
HUDSONTP	143.6	93.2	158.0	71.7	81.1	62.5	66.4	78.4	111.9	75.7	38.1	62.3	1,042.8
LINDENVFT	9.9	11.3	38.4	20.3	22.8	18.4	9.0	14.2	17.9	18.0	6.0	32.2	218.3
NEPTUNE	0.6	13.3	9.2	14.4	17.1	18.3	11.0	9.5	11.3	4.0	8.1	5.1	121.9
NYIS	194.5	205.4	122.0	18.0	16.2	94.5	75.2	223.8	145.9	83.1	82.9	233.5	1,495.1
Southern Imports	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0								0.0
Southern Exports	22.8	50.0	52.1	56.3	47.8								228.9
SOUTHEAST	0.0	0.0	0.0	0.0	0.0								0.0
SOUTHEXP	22.8	50.0	52.1	56.3	47.8								228.9
SOUTH						2.8	53.0	20.1	45.0	25.7	19.7	37.8	204.3
Total Interfaces	1,011.9	1,142.2	681.9	250.0	227.7	333.2	342.3	412.9	404.5	330.8	192.8	501.2	5,831.4

Table 9-19 Active scheduling interfaces: 2021[25]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

25 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of December 31, 2021, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Figure 9-3 PJM's footprint and its external scheduling interfaces

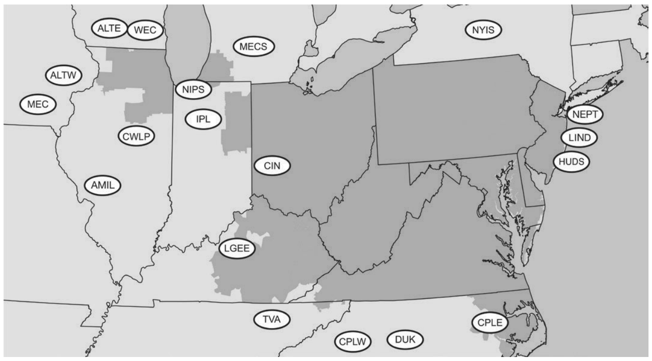
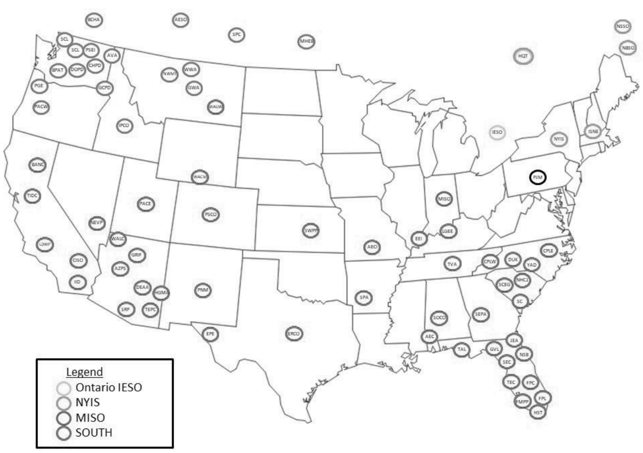


Table 9-20 Active scheduled interface pricing points: 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active							
SOUTHIMP	Active	Active	Active	Active	Active							
South						Active	Active	Active	Active	Active	Active	Active

Figure 9-4 External balancing authority default interface pricing point assignments



Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[26]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market-based price differentials at interface pricing points that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at PJM's borders. For example, if a 100 MW transaction were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Correspondingly, there would be no scheduled flows at the PJM/Southern interface border, but there would be 100 MW of actual flows on the interface. In 2021, there were net scheduled flows of 567 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In 2021, net scheduled interchange was -37,767 GWh and net actual interchange was -37,813 GWh, a difference of 47 GWh. In 2020, net scheduled interchange was -41,630 GWh and net actual interchange was -41,716 GWh, a difference of 86 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange using unilateral or bilateral paybacks. Inadvertent interchange accumulations that are paid back unilaterally are paid by controlling to a non-zero area control error (ACE). For example, Table 9-21 shows that PJM had 47 GW of inadvertent interchange in 2021. To reduce this inadvertent interchange, PJM can control to an ACE less than zero, which would result in under generating. By way of the power balance equation, power would flow into PJM from its neighboring balancing authority areas. This would create additional actual imports that were not scheduled, thus reducing the overall inadvertent. To maintain reliability, unilateral paybacks are accounted for in the control performance standard calculations. Bilateral paybacks are scheduled with other balancing authority areas by scheduling a correction and incorporating that amount as a bias in the energy management system.[27]

Table 9-21 shows that in 2021, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -1,637 GWh of net scheduled interchange and -10,298 GWh of net actual interchange, a difference of 8,529 GWh.

26 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

27 See PJM. "Manual 12: Balancing Operations," Rev. 43 (June 6, 2021).

Table 9-21 Net scheduled and actual PJM flows by interface (GWh): 2021

	Actual	Net Scheduled	Difference (GWh)
CPLE	(560)	(183)	(377)
CPLW	(424)	19	(442)
DUK	2,308	928	1,379
LGEE	1,470	(664)	2,133
MISO	(32,087)	(24,317)	(7,770)
ALTE	(2,678)	(2,827)	148
ALTW	(2,498)	(284)	(2,213)
AMIL	(2,015)	123	(2,138)
CIN	(6,324)	(8,856)	2,532
CWLP	(453)	0	(453)
IPL	(2,813)	(827)	(1,986)
MEC	(7,151)	(6,048)	(1,103)
MECS	(2,177)	(3,486)	1,309
NIPS	(10,972)	(1,637)	(9,336)
WEC	4,996	(475)	5,471
NYISO	(13,452)	(13,604)	151
HUDS	(2,865)	(2,865)	0
LIND	(2,293)	(2,293)	0
NEPT	(2,777)	(2,777)	0
NYIS	(5,518)	(5,669)	151
TVA	4,933	54	4,879
Total	(37,813)	(37,767)	(47)

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[28] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SOUTH interface pricing point net schedule totals because SPP is mapped to the SOUTH interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path. Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point.

On June 1, 2021, PJM consolidated the SouthIMP and SouthEXP interface pricing points to the SOUTH interface pricing point. Because the SouthIMP and SouthEXP interface pricing points were the same physical point, if there were net actual exports from the PJM footprint to the southern region, by definition, there could not be net actual imports into the PJM footprint from the southern region and therefore there would not be actual flows at the SouthIMP interface pricing point. In the case of PJM's southern border, loop flows can be analyzed by comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points. To accurately calculate the loop flows from the southern region, the net actual flows from the southern region are compared to the net scheduled flows from the southern region. The net actual flows from the southern region are determined by summing the total southern import actual flows (10,298 GWh), the total southern export actual flows (-7,322 GWh) and the total SOUTH actual flows (4,751 GWh) for 7,726 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (1,769 GWh), the total southern export scheduled flows (-1,673 GWh) and the total SOUTH scheduled flows (626 GWh) for 722 GWh of net imports. In 2021, the loop flows at the southern region were the difference between the southern region net scheduled flows (722 GW) and the southern region net actual flows (7,726 GWh) for a total of 7,004 GWh of loop flows.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO interface pricing point to

28 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

reflect the actual power flows across both the MISO/PJM and NYISO/PJM interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Table 9-22 shows actual flows associated with the IMO interface pricing point as zero because there is no PJM/IMO Interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-22 PJM flows by interface pricing point (GWh): 2021

	Actual	Net Scheduled	Difference (GWh)
IMO	0	413	(413)
MISO	(32,087)	(25,284)	(6,803)
NYISO	(13,452)	(13,618)	165
HUDSONTP	(2,865)	(2,865)	(0)
LINDENVFT	(2,293)	(2,293)	0
NEPTUNE	(2,777)	(2,777)	0
NYIS	(5,518)	(5,683)	165
Southern Imports	10,298	1,769	8,529
SOUTHEAST	0	0	0
SOUTHIMP	10,298	1,769	8,529
Southern Exports	(7,322)	(1,673)	(5,649)
SOUTHEAST	0	0	0
SOUTHEXP	(7,322)	(1,673)	(5,649)
SOUTH	4,751	626	4,125
Total	(37,813)	(37,767)	(47)

Table 9-23 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the IMO entered the PJM energy market. For example, Table 9-25 shows that 399 of the 413 GWh (96.6 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO.

Table 9-23 shows that in 2021, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 1,769 GWh of net scheduled interchange and 10,298 GWh of net actual interchange, a difference of 8,529 GWh.

Table 9-23 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): 2021

	Actual	Net Scheduled	Difference (GWh)
MISO	(32,087)	(24,885)	(7,202)
NYISO	(13,452)	(13,604)	151
HUDSONTP	(2,865)	(2,865)	(0)
LINDENVFT	(2,293)	(2,293)	0
NEPTUNE	(2,777)	(2,777)	0
NYIS	(5,518)	(5,669)	151
Southern Imports	10,298	1,769	8,529
SOUTHEAST	0	0	0
SOUTHIMP	10,298	1,769	8,529
Southern Exports	(7,322)	(1,673)	(5,649)
SOUTHEAST	0	0	0
SOUTHEXP	(7,322)	(1,673)	(5,649)
SOUTH	4,751	626	4,125
Total	(37,813)	(37,767)	(47)

The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

PJM attempts to ensure that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game the markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loop flow would be reduced.

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-24 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the interface pricing points that were assigned to energy transactions that had paths at each of PJM's interfaces. For example, Table 9-24 shows that in 2021, the majority of imports to the PJM energy market for which a market participant specified Ameren-Illinois (AMIL) as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the SOUTHIMP Interface, and thus actual flows were assigned the SOUTH interface pricing point (700 GWh). The majority of exports from the PJM energy market for which a market participant specified AMIL as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM energy market at the MISO Interface, and were assigned the MISO interface pricing point (-569 GWh).

Table 9-24 Net scheduled and actual flows by interface and interface pricing point (GWh): 2021

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(2,678)	(2,827)	148	LGEE		1,470	(664)	2,133
	IMO	0	47	(47)		SOUTHEXP	(3,467)	(357)	(3,111)
	MISO	(2,678)	(2,873)	194		SOUTHIMP	4,149	121	4,028
	SOUTHEXP	0	(3)	3		SOUTH	787	(428)	1,216
	SOUTH	0	2	(2)	LIND		(2,293)	(2,293)	0
ALTW		(2,498)	(284)	(2,213)		LINDENVFT	(2,293)	(2,293)	0
	IMO	0	2	(2)	MEC		(7,151)	(6,048)	(1,103)
	MISO	(2,498)	(286)	(2,212)		IMO	0	(1)	1
	SOUTH	0	(0)	0		MISO	(7,151)	(6,038)	(1,113)
AMIL		(2,015)	123	(2,138)		SOUTHEXP	0	(9)	9
	MISO	(2,015)	(569)	(1,446)		SOUTHIMP	0	2	(2)
	SOUTHEXP	0	(35)	35		SOUTH	0	(2)	2
	SOUTHIMP	0	26	(26)	MECS		(2,177)	(3,486)	1,309
	SOUTH	0	700	(700)		IMO	0	369	(369)
CIN		(6,324)	(8,856)	2,532		MISO	(2,177)	(3,888)	1,711
	IMO	0	(36)	36		SOUTHEXP	0	(13)	13
	MISO	(6,324)	(8,636)	2,311		SOUTHIMP	0	1	(1)
	SOUTHEXP	0	(135)	135		SOUTH	0	45	(45)
	SOUTHIMP	0	11	(11)	NEPT		(2,777)	(2,777)	0
	SOUTH	0	(60)	60		NEPTUNE	(2,777)	(2,777)	0
CPLE		(560)	(183)	(377)	NIPS		(10,972)	(1,637)	(9,336)
	SOUTHEXP	(1,613)	(408)	(1,206)		IMO	0	1	(1)
	SOUTHIMP	1,126	439	687		MISO	(10,972)	(1,637)	(9,335)
	SOUTH	(72)	(215)	142	NYIS		(5,518)	(5,669)	151
CPLW		(424)	19	(442)		IMO	0	14	(14)
	SOUTHEXP	(232)	0	(232)		NYIS	(5,518)	(5,683)	165
	SOUTHIMP	61	2	59	TVA		4,933	54	4,879
	SOUTH	(253)	17	(269)		MISO	0	(0)	0
CWLP		(453)	0	(453)		SOUTHEXP	(1,572)	(316)	(1,256)
	MISO	(453)	0	(453)		SOUTHIMP	3,592	362	3,231
DUK		2,308	928	1,379		SOUTH	2,912	9	2,904
	SOUTHEXP	(438)	(307)	(131)	WEC		4,996	(475)	5,471
	SOUTHIMP	1,370	796	573		MISO	4,996	(583)	5,579
	SOUTH	1,376	439	937		SOUTHEXP	0	(22)	22
HUDS		(2,865)	(2,865)	0		SOUTHIMP	0	9	(9)
	HUDSONTP	(2,865)	(2,865)	0		SOUTH	0	121	(121)
IPL		(2,813)	(827)	(1,986)	Grand Total		(37,813)	(37,767)	(47)
	IMO	0	18	(18)					
	MISO	(2,813)	(775)	(2,038)					
	SOUTHEXP	0	(68)	68					
	SOUTHIMP	0	0	(0)					
	SOUTH	0	(2)	2					

Table 9-25 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-24. Table 9-25 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-25 shows that in 2021, the majority of imports to the PJM energy market for which a market participant specified a generation control area for which it was assigned the IMO interface pricing point, had a path that entered the PJM energy market at the MECS Interface (369 GWh).

Table 9-25 Net scheduled and actual flows by interface pricing point and interface (GWh): 2021

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
HUDSONTP		(2,865)	(2,865)	0	SOUTH		4,751	626	4,125
	HUDS	(2,865)	(2,865)	0		ALTE	0	2	(2)
IMO		0	413	(413)		ALTW	0	(0)	0
	ALTE	0	47	(47)		AMIL	0	700	(700)
	ALTW	0	2	(2)		CIN	0	(60)	60
	CIN	0	(36)	36		CPLE	(72)	(215)	142
	IPL	0	18	(18)		CPLW	(253)	17	(269)
	MEC	0	(1)	1		DUK	1,376	439	937
	MECS	0	369	(369)		IPL	0	(2)	2
	NIPS	0	1	(1)		LGEE	787	(428)	1,216
	NYIS	0	14	(14)		MEC	0	(2)	2
LINDENVFT		(2,293)	(2,293)	0		MECS	0	45	(45)
	LIND	(2,293)	(2,293)	0		TVA	2,912	9	2,904
MISO		(32,087)	(25,284)	(6,803)		WEC	0	121	(121)
	ALTE	(2,678)	(2,873)	194	SOUTHEXP		(7,322)	(1,673)	(5,649)
	ALTW	(2,498)	(286)	(2,212)		ALTE	0	(3)	3
	AMIL	(2,015)	(569)	(1,446)		AMIL	0	(35)	35
	CIN	(6,324)	(8,636)	2,311		CIN	0	(135)	135
	CWLP	(453)	0	(453)		CPLE	(1,613)	(408)	(1,206)
	IPL	(2,813)	(775)	(2,038)		CPLW	(232)	0	(232)
	MEC	(7,151)	(6,038)	(1,113)		DUK	(438)	(307)	(131)
	MECS	(2,177)	(3,888)	1,711		IPL	0	(68)	68
	NIPS	(10,972)	(1,637)	(9,335)		LGEE	(3,467)	(357)	(3,111)
	TVA	0	(0)	0		MEC	0	(9)	9
	WEC	4,996	(583)	5,579		MECS	0	(13)	13
NEPTUNE		(2,777)	(2,777)	0		TVA	(1,572)	(316)	(1,256)
	NEPT	(2,777)	(2,777)	0		WEC	0	(22)	22
NYIS		(5,518)	(5,683)	165	SOUTHIMP		10,298	1,769	8,529
	NYIS	(5,518)	(5,683)	165		AMIL	0	26	(26)
						CIN	0	11	(11)
						CPLE	1,126	439	687
						CPLW	61	2	59
						DUK	1,370	796	573
						IPL	0	0	(0)
						LGEE	4,149	121	4,028
						MEC	0	2	(2)
						MECS	0	1	(1)
						TVA	3,592	362	3,231
						WEC	0	9	(9)
					Grand Total		(37,813)	(37,767)	(47)

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on nonmarket areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and nonmarket areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (nonmarket areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. The Commission required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[29]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data include the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[30]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. The available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

Area Control Error (ACE) Data

Area control error (ACE) data provides information about how well each balancing authority is matching their

29 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

30 141 FERC ¶ 61,235 (2012).

generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual websites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU recommends, that in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. MISO's LMP calculations at the buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs. The interface definitions led to questions about the level of congestion included in interchange pricing.[31]

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over

31 See "LMP Aggregate Definitions," (December 8, 2021) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.ashx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

80 percent of the hourly tie line flows between PJM and MISO occurred on 10 ties composed of MISO and PJM monitored facilities. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Real-Time and Day-Ahead PJM/MISO Interface Prices

In 2021, the direction of flow was consistent with price differentials in 59.9 percent of the hours. Table 9-26 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Figure 9-5 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In 2021, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 5,249 hours (59.9 percent of all hours), and was inconsistent with price differentials in 3,511 hours (40.1 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,511 hours where flows were in a direction inconsistent with price differences, 2,859 of those hours (81.4 percent) had a price difference greater than or equal to $1.00 and 1,521 of those hours (43.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $469.04. Of the 5,249 hours where flows were consistent with price differences, 4,450 of those hours (84.8 percent) had a price difference greater than or equal to $1.00 and 1,936 of all such hours (36.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $566.78.

Table 9-26 PJM and MISO flow based hours and price differences: 2021

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	5,250	$8.79
	Consistent Flow (PJM to MISO)	5,249	$8.79
	Inconsistent Flow (MISO to PJM)	1	$9.65
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	3,510	$10.80
	Consistent Flow (MISO to PJM)	0	$0.00
	Inconsistent Flow (PJM to MISO)	3,510	$10.80
	No Flow	0	$0.00

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): 2021

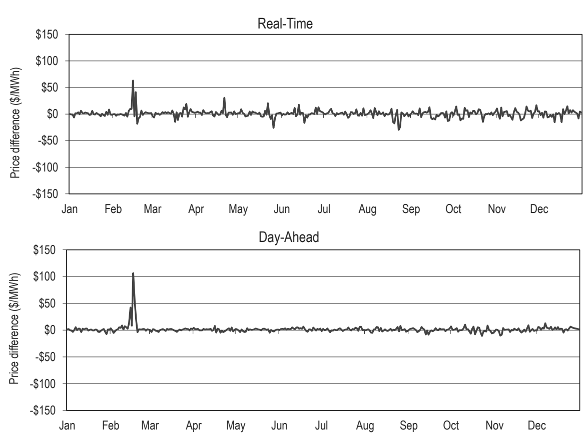


Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: 2021

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	3,511	100.0%	5,249	100.0%
$1.00	2,859	81.4%	4,450	84.8%
$5.00	1,521	43.3%	1,936	36.9%
$10.00	887	25.3%	982	18.7%
$15.00	599	17.1%	605	11.5%
$20.00	452	12.9%	423	8.1%
$25.00	360	10.3%	340	6.5%
$50.00	129	3.7%	143	2.7%
$75.00	67	1.9%	85	1.6%
$100.00	41	1.2%	51	1.0%
$200.00	12	0.3%	14	0.3%
$300.00	5	0.1%	4	0.1%
$400.00	2	0.1%	2	0.0%
$500.00	0	0.0%	1	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[32]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. Prior to May 1, 2017, PJM used two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP. The NYISO uses proxy buses to calculate interface prices with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21 percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

The PJM/NYIS interface definition using two buses was created to include the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change. Effective May 1, 2017, PJM replaced the old PJM/NYIS interface price definition. The new PJM/NYIS interface price is based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

Real-Time and Day-Ahead PJM/NYISO Interface Prices

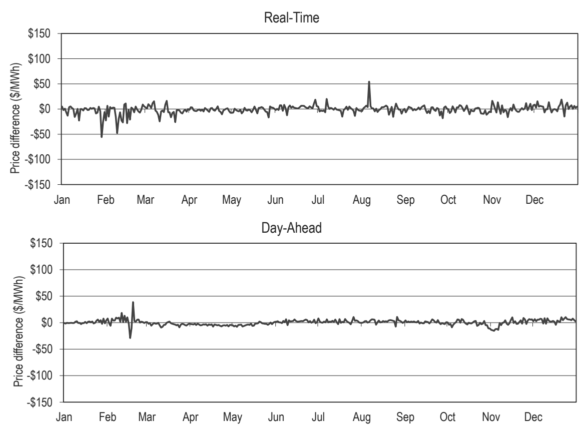
In 2021, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 56.6 percent of the hours in 2021. Table 9-28 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-6 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

32 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Table 9-28 PJM and NYISO flow based hours and price differences: 2021[33]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	4,637	$9.40
	Consistent Flow (PJM to NYIS)	4,149	$9.30
	Inconsistent Flow (NYIS to PJM)	488	$10.26
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	4,123	$12.72
	Consistent Flow (NYIS to PJM)	808	$9.43
	Inconsistent Flow (PJM to NYIS)	3,315	$13.53
	No Flow	0	$0.00

Figure 9-6 Price differences (NY/PJM proxy - PJM/NYIS Interface): 2021



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In 2021, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 4,957 hours (56.6 percent of all hours), and was inconsistent with price differences in 3,803 hours (43.4 percent of all hours). Table 9-29 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 3,803 hours where flows were in a direction inconsistent with price differences, 3,357 of those hours (88.3 percent) had a price difference greater than or equal to $1.00 and 2,012 of all those hours (52.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $379.02. Of the 4,957 hours where flows were consistent with price differences, 4,472 of those hours (90.2 percent) had a price difference greater than or equal to $1.00 and 2,563 of all such hours (51.7 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $675.62.

Table 9-29 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: 2021

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	3,803	100.0%	4,957	100.0%
$1.00	3,357	88.3%	4,472	90.2%
$5.00	2,012	52.9%	2,563	51.7%
$10.00	1,144	30.1%	1,220	24.6%
$15.00	770	20.2%	648	13.1%
$20.00	568	14.9%	406	8.2%
$25.00	439	11.5%	302	6.1%
$50.00	184	4.8%	93	1.9%
$75.00	100	2.6%	50	1.0%
$100.00	63	1.7%	29	0.6%
$200.00	22	0.6%	6	0.1%
$300.00	8	0.2%	3	0.1%
$400.00	0	0.0%	3	0.1%
$500.00	0	0.0%	3	0.1%

33 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-30, including average prices and measures of variability.

Table 9-30 PJM, NYISO and MISO border price averages: 2021[34]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$36.18	$35.64	$34.90	$36.05
	ISO Price at PJM Border	$35.15	$36.59	$35.24	$37.52
	Difference at Border (PJM-ISO)	$1.02	($0.94)	($0.34)	($1.47)
	Average Absolute Value of Interval Difference at Border	$47.41	$49.29	$4.59	$8.42
	Sign Changes per Day	41.2	49.3	2.8	3.8
Standard Deviation	PJM Price at ISO Border	$45.00	$40.80	$15.61	$18.51
	ISO Price at PJM Border	$31.87	$41.27	$16.28	$22.29
	Difference at Border (PJM-ISO)	$49.22	$50.70	$6.36	$9.32

Neptune Underwater Transmission Line to Long Island, New York

The Neptune Line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. The flows were consistent with price differentials in 74.8 percent of the hours in 2021. Table 9-31 shows the number of hours and average hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

Table 9-31 PJM and NYISO flow based hours and price differences (Neptune): 2021

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	7,454	$28.48
	Consistent Flow (PJM to NYIS)	6,556	$27.96
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	898	$32.28
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	1,306	$22.67
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,260	$23.30
	No Flow	46	$5.31

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line ("Out Service") and another transmission service reservation is required on the Neptune HVDC Line ("Neptune Service").[35] The PJM Out Service is covered by normal PJM OASIS business operations.[36] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 2021, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-32 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July 2007. Table 9-32 shows that in 2021, the primary rights holder was responsible for 100 percent

34 Effective April 1, 2018, PJM implemented 5 minute LMP settlements in the real-time energy market. The sign changes per day represented in this table reflect the number of intervals where the sign changed per day. For the real-time energy market, there are 288 five minute intervals. For the day-ahead market there are 24 hourly intervals.

35 See OASIS "PJM Business Practices for Neptune Transmission Service," (August 21, 2015) <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>.

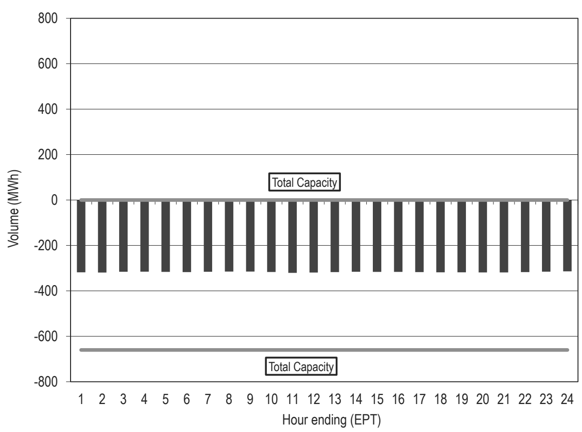
36 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 10 (October 27, 2021) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for 2021.

Table 9-32 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through December 2021

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 9-7 Neptune hourly average flow: 2021



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 315 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 76.8 percent of the hours in 2021. Table 9-33 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden Bus based on LMP differences and flow direction.

Table 9-33 PJM and NYISO flow based hours and price differences (Linden): 2021

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	6,855	$14.07
	Consistent Flow (PJM to NYIS)	6,730	$14.11
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	125	$12.06
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	1,905	$13.05
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,839	$13.17
	No Flow	66	$9.62

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[37] The PJM Out Service is covered by normal PJM OASIS business operations.[38] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

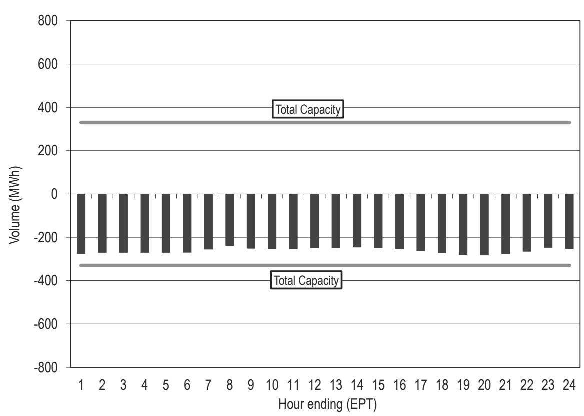
Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 2021, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-34 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-34 shows that in 2021, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-8 shows the hourly average flow across the Linden VFT Line for 2021.

Table 9-34 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through December 2021

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	100.00%	100.00%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	27.27%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 9-8 Linden hourly average flow: 2021[39]



37 See OASIS "PJM Business Practices for Linden VFT Transmission Service," (June 1, 2011) <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.
38 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 10 (October 27, 2021) <https://www.pjm.com/-/media/etools/oasis/regional-practices-clean-pdf.ashx>.
39 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (Con Ed) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC Line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC had only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of nonfirm withdrawal rights). The flows were consistent with price differentials in 69.9 percent of the hours in 2021. Table 9-35 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-35 PJM and NYISO flow based hours and price differences (Hudson): 2021

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	6,314	$12.58
	Consistent Flow (PJM to NYIS)	6,127	$12.69
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	187	$9.14
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	2,446	$16.70
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	2,387	$16.95
	No Flow	59	$6.46

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line ("Out Service") and another transmission service reservation is required on the Hudson Line ("Hudson Service").[40] The PJM Out Service is covered by normal PJM OASIS business operations.[41] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 2021, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

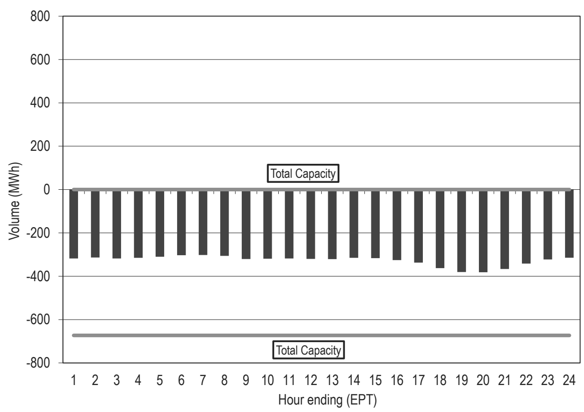
40 See OASIS "PJM Business Practices for Hudson Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.
41 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 10 (October 27, 2021) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-36 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-36 shows that in 2021, the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Hudson Line in all months. Figure 9-9 shows the hourly average flow across the Hudson Line for 2021.

Table 9-36 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through December 2021[42]

	2013	2014	2015	2016	2017	2018	2019	2020	2021
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%	29.70%	37.64%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%	23.61%	47.37%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.42%	87.24%	53.27%
April	NA	100.00%	100.00%	NA	NA	15.13%	100.00%	10.02%	70.90%
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	100.00%	20.53%	65.15%
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	44.98%	38.26%	73.81%
July	100.00%	18.51%	84.34%	NA	NA	16.26%	36.43%	27.56%	76.56%
August	100.00%	75.17%	65.48%	NA	NA	19.24%	43.10%	35.64%	59.09%
September	100.00%	75.31%	78.73%	NA	NA	22.90%	43.42%	30.75%	53.66%
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	33.60%	52.58%	56.26%
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	44.36%	38.60%	65.24%
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	41.78%	38.82%	61.11%

Figure 9-9 Hudson hourly average flow: 2021



Interchange Activity During High Load Hours

The PJM metered system peak load during 2021 was 145,563 MW in the HE 1700 on August 24, 2021. PJM was a net scheduled exporter of energy in all hours on August 24, 2021, with average hourly scheduled exports of 4,342 MW. During HE 1700 on August 24, 2021, PJM had net scheduled exports of 2,775 MW and net metered actual exports of 2,987 MW. Net transaction exports during this time were inconsistent with the price differences between PJM and MISO, PJM and the NYISO, the PJM/LIND interface and the NYIS/Linden bus and the PJM/HUDS Interface and the NYIS/Hudson bus. Net transaction exports during this time were consistent with price differences between the PJM/NEPT interface and the NYIS/Neptune bus. During August 2021, PJM was a net scheduled exporter of energy in all hours. During August 2021, the average hourly scheduled interchange was -5,422 MW (representing 5.3 percent of the average hourly load of 102,666 MW in August 2021).

42 The designation of "NA" means there was no flow on the Hudson Line during those months.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements, including: operating agreements with MISO and the NYISO; a reliability agreement with TVA; an operating agreement with Duke Energy Progress, Inc.; a reliability coordination agreement with VACAR South; a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC); and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-37 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-37 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA	PJM-DEP	PJM-VACAR	VACAR Reserve Sharing Agreement	PJM-WEP	Northeastern Protocol
Data Exhange								
Real-Time Data	YES	YES	YES	YES	YES	NO	YES	NO
Projected Data	YES	YES	YES	YES	NO		NO	NO
SCADA Data	YES	YES	YES	YES	NO		NO	NO
EMS Models	YES	YES	YES	YES	NO		NO	YES
Operations Planning Data	YES	YES	YES	YES	NO		NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO		NO	YES
Near-Term System Coordination								
Operating Limit Violation Assistance	YES	YES	YES	YES	YES		NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES		NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES		NO	NO
Outage Coordination	YES	YES	YES	YES	YES		NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO		NO	YES
Congestion Management Process								
ATC Coordination	YES	YES	YES	YES	NO		NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO		NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO		NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	NO	NO		NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO		YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement
PJM-NYISO = New York ISO/PJM Joint Operating Agreement
PJM-TVA = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[43]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[44]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP. Prior to June 1, 2017, MISO used all of the

43 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.
44 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[45] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

An operating entity is an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads and other operating entities.[46] Coordinated flowgates are identified to determine which flowgates an operating entity affects significantly. This set of flowgates may then be used in the congestion management process. An operating entity will conduct sensitivity studies to determine which flowgates are significantly affected by the flows of the operating entity's control zones (historic control areas that existed in the IDC). An operating entity identifies these flowgates by performing five studies to determine which flowgates the operating entity will monitor and help control. These studies include generation to load distribution factor studies, transfer distribution factor analysis and an external asynchronous resource study. An operating entity may also specify additional flowgates that have not passed any of the five studies to be coordinated flowgates where the operating entity expects to use the TLR process to manage congestion.[47] A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of January 1, 2021, PJM had 143 flowgates eligible for M2M (Market to Market) coordination. In 2021, PJM added 49 flowgates and deleted 13 flowgates, resulting in 179 flowgates eligible for M2M coordination as of December 31, 2021. As of January 1, 2021, MISO had 147 flowgates eligible for M2M coordination. In 2021, MISO added 85 flowgates and deleted 75 flowgates, resulting in 157 flowgates eligible for M2M coordination as of December 31, 2021.

The firm flow entitlement (FFE) represents the amount of historic 2004 flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the nonmonitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the nonmonitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the nonmonitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the nonmonitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE.

April 1, 2004, known as the freeze date, is used to determine the firm rights on flowgates based on historic premarket firm flows as of that date. In the past 16 years, topology and market changes have occurred, making the 2004 flows irrelevant in 2021. The RTOs and stakeholders recognize that a modification to the freeze date is necessary.[48] PJM and MISO stakeholders have spent several years on the freeze date issues. Discussions regarding the Firm Flow Limit (FFL) solutions between market and nonmarket areas are also ongoing. No resolution to these issues appears imminent. The final resolution to the freeze date alternative should account for the investments made by each RTO in the transmission system. The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues.

In 2021, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

45 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

46 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

47 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

48 See "*Freeze Date Alternatives*," (May 21, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20190521/20190521-item-01-freeze-date-update.ashx>.

Figure 9-10 PJM/MISO credits for coordinated congestion management: January 2020 through December 2021[49]

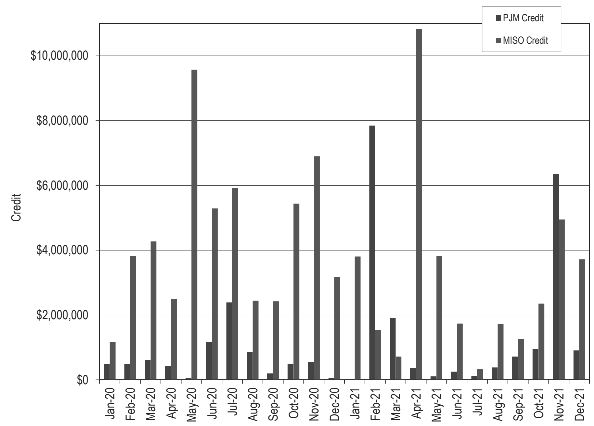
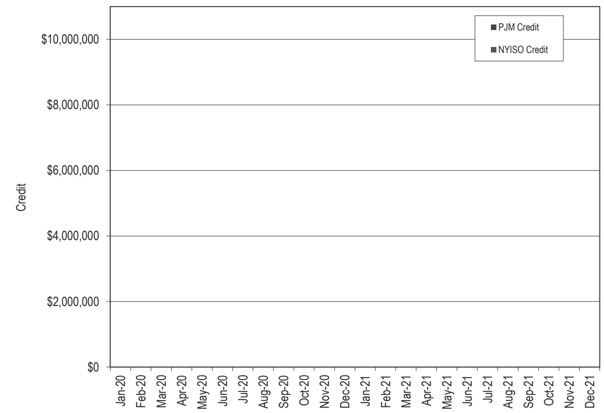


Figure 9-11 PJM/NYISO credits for coordinated congestion management (flowgates): January 2020 through December 2021[52]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[50]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions would address RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch would be to mitigate post-contingency overloads of transmission equipment on the New York side of the East Towanda-Hillside 230 kV Transmission Line. The agreement allows for the RTOs to control for this contingency without the exchange of payments for redispatch.[51]

In 2021, market to market operations did not result in NYISO and PJM redispatching units to control congestion on M2M flowgates. Therefore, there was no exchange of payments for redispatch in 2021. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located at the PJM/NYIS border. This real-time coordination results in an efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real time to manage constraints.[53] For each M2M flowgate, a PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs

49 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

50 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

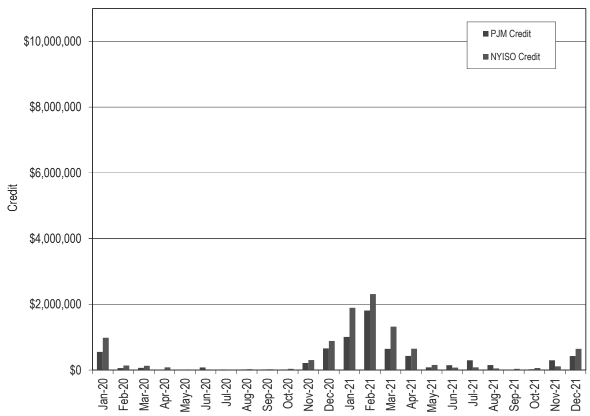
51 See NYISO Filing, FERC Docket No. ER19-2282-000 (June 28, 2019).

52 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

53 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In 2021, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. Figure 9-12 shows the PAR credits for coordinated congestion management between PJM and NYISO.

Figure 9-12 PJM/NYISO credits for coordinated congestion management (PARs): January 2020 through December 2021[54]



PJM and TVA Joint Reliability Coordination Agreement (JRCA)[55]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement remained in effect in 2021.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[56]

On September 9, 2005, FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to include a CMP under Article 14 of the JOA.[57] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc., now a subsidiary of Duke Energy, changed its name to Duke Energy Progress (DEP).

On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.[58] PJM and DEP requested an effective date of July 22, 2019, for the filed revisions. On July 2, 2019, the Commission issued a letter order accepted the revisions to the JOA to delete the congestion management agreement effective July 22, 2019.[59]

PJM and VACAR South Reliability Coordination Agreement[60]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in 2021.

54 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
55 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.
56 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (July 22, 2019) <http://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.
57 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).
58 See *PJM Interconnection, L.L.C*, Docket No. ER19-1905-000 (May 20, 2019).
59 FERC Docket No. ER19-1905-000.
60 See "PJM-VACAR South RC Agreement," (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) is a combination of agreements among the entities in the VACAR Subregion including Dominion.[61] VACAR is a subregion of the SERC Reliability Corporation (SERC) region. The agreement remained in effect in 2021. The agreement requires that each entity maintain primary reserves to meet the VACAR contingency reserve commitment (VACAR reserves) and deploy such reserves in the case of an emergency (e.g. loss of a unit in VACAR).[62] Dominion is the only party to the VRSA that is also a transmission owner and a generation owner in PJM. The VRSA is not a public agreement. PJM is not a party to the VRSA. However, as the reliability coordinator for Dominion Virginia Power, PJM is responsible for scheduling Dominion's required reserves in the SERC region as described in the PJM manuals.[63]

There are issues with the VRSA. PJM is expected to implement reserve market changes in 2022. These changes include the consolidation of synchronized reserves tier 1 and tier 2 and the reserve must offer requirement. With these changes, it will not be possible for Dominion to hold reserves to meet its obligations under the VRSA without failing the must offer requirement in PJM. Under the reserve market changes, it will not be possible for Dominion to meet both the VRSA and the PJM reserve rules. The Market Monitor recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. The Market Monitor recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas.[64]

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[65]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in 2021.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[66]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in 2021.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher was two in 2020 and two in 2021.[67] The number of different flowgates for which PJM declared a TLR 3a or higher was two in 2020, and one in 2021. The total MWh of transactions curtailed was 1,789 in 2020 and zero in 2021.

61 VRSA entities: Dominion, Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.

62 *See* SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.

63 See PJM. "Manual 13: Emergency Operations," Rev. 82 (January 1, 2022).

64 See the *2021 State of the Market Report for PJM*, Volume 2, Section 10: Ancillary Services, "VACAR Reserve Sharing Agreement" for more information on issues identified with the VACAR Reserve Sharing Agreement.

65 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C.," (July 20, 2013) <https://www.pjm.com/directory/merged-tariffs/rs43.pdf>.

66 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.

67 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2020 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

The number of MISO issued TLRs of level 3a or higher decreased from 93 in 2020 to 75 in 2021. The number of different flowgates for which MISO declared a TLR 3a was 17 in 2020, and 23 in 2021. The total MWh of transaction curtailments increased by 20.0 percent from 58,520 MWh in 2020 to 70,231 MWh in 2021.

The number of NYISO issued TLRs of level 3a or higher decreased from two in 2020 to three in 2021. The number of different flowgates for which NYISO declared a TLR 3a or higher was one in 2020, and two in 2021. The total MWh of transaction curtailments increased by 2,594.6 percent from 1,030 MWh in 2020, to 27,754 MWh in 2021.

Table 9-38 PJM, MISO, and NYISO TLR procedures: 2021[68]

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-21	0	7	0	0	3	0	0	1,642	0
Feb-21	2	17	0	1	10	0	0	38,912	0
Mar-21	0	6	1	0	3	1	0	4,776	390
Apr-21	0	9	0	0	3	0	0	7,259	0
May-21	0	2	0	0	1	0	0	1,964	0
Jun-21	0	7	0	0	3	0	0	3,425	0
Jul-21	0	4	0	0	2	0	0	1,833	0
Aug-21	0	1	0	0	1	0	0	0	0
Sep-21	0	3	0	0	3	0	0	915	0
Oct-21	0	4	1	0	4	1	0	1,234	855
Nov-21	0	10	0	0	7	0	0	7,558	0
Dec-21	0	5	1	0	2	1	0	713	26,509
Total	2	75	3	1	23	2	0	70,231	27,754

Table 9-39 Number of TLRs by TLR level by reliability coordinator: 2021[69]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2021	MISO	32	30	0	7	6	0	75
	NYIS	3	0	0	0	0	0	3
	ONT	3	0	0	0	0	0	3
	PJM	0	2	0	0	0	0	2
	SOCO	0	0	0	0	0	0	0
	SWPP	4	12	5	23	23	0	67
	TVA	15	11	0	32	32	0	90
	VACS	3	7	0	0	0	0	10
Total		60	62	5	62	61	0	250

68 The total row in the columns of the number of unique flowgates that experience TLRs are not a sum of the individual months. The total row represents the number of unique flowgates that have experienced TLRs for the year to date.

69 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.

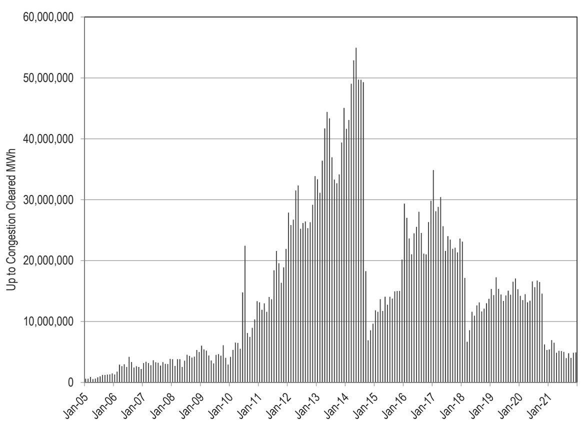
Up To Congestion Transactions

The original purpose, in 2000, of up to congestion transactions (UTC) was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the day-ahead energy market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the real-time energy market.[70]

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions were not required to pay uplift charges from their introduction in 2010 through October 31, 2020. On July 16, 2020, FERC issued an Order directing PJM to revise uplift allocation rules to allocate uplift to one side of up to congestion transactions.[71] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. Up to congestion transactions also negatively affect FTR funding.[72]

Up to congestion transaction volumes decreased following the allocation of uplift charges to UTCs effective November 1, 2020. The average number of up to congestion bids submitted in the day-ahead energy market decreased by 46.6 percent, from 48,618 bids per day in 2020 to 25,965 bids per day in 2021. The average number of up to congestion bids cleared in the day-ahead energy market decreased by 48.1 percent, from 24,503 bids per day in 2020 to 12,715 bids per day in 2021. The average volume of up to congestion bids submitted in the day-ahead energy market decreased by 58.2 percent, from 1,092.014 MWh per day in 2020, to 456,330 MWh per day in 2021. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 61.4 percent, from 438,170 MWh per day in 2020, to 169,201 MWh per day in 2021.

Figure 9-13 Monthly up to congestion cleared bids in MWh: January 2005 through December 2021



70 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.
71 172 FERC ¶ 61,046 (2020).
72 See the *2021 State of the Market Report for PJM*, Volume II, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

Table 9-40 Monthly volume of cleared and submitted up to congestion bids: January 2020 through December 2021

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-20	5,709,294	2,231,205	1,944,774	18,039,136	27,924,410	275,752	162,609	75,183	1,039,001	1,552,545
Feb-20	5,676,276	2,666,146	2,199,490	17,493,382	28,035,292	242,264	146,844	65,051	1,030,601	1,484,760
Mar-20	6,665,180	2,978,585	2,003,110	18,814,938	30,461,812	251,993	161,948	66,569	983,109	1,463,619
Apr-20	6,091,885	2,682,191	1,468,174	16,612,116	26,854,366	254,545	137,594	52,775	893,782	1,338,696
May-20	6,271,609	1,965,274	1,075,904	21,565,323	30,878,110	331,575	137,922	60,794	1,273,857	1,804,148
Jun-20	6,831,949	2,804,284	1,743,982	31,474,224	42,854,440	334,466	159,856	63,796	1,404,345	1,962,463
Jul-20	7,876,157	2,322,606	1,988,024	35,708,931	47,895,717	288,710	109,436	65,635	1,425,030	1,888,811
Aug-20	7,758,436	2,285,138	2,157,739	34,944,219	47,145,532	246,363	101,479	60,503	1,307,254	1,715,599
Sep-20	7,498,635	3,279,523	2,074,365	34,571,326	47,423,850	236,272	113,749	68,013	1,249,116	1,667,150
Oct-20	3,329,528	3,582,220	1,038,616	33,641,971	41,592,335	116,339	118,061	36,445	1,185,280	1,456,125
Nov-20	1,930,357	707,420	554,083	12,050,981	15,242,840	57,036	33,287	13,729	654,986	759,038
Dec-20	1,719,227	1,017,140	131,755	10,500,435	13,368,557	59,542	57,003	8,237	576,292	701,074
Jan-21	2,282,816	1,938,192	276,618	10,688,893	15,186,519	78,521	88,947	15,555	607,025	790,048
Feb-21	2,560,448	1,732,756	251,312	11,403,148	15,947,664	79,571	91,052	12,982	641,265	824,870
Mar-21	2,517,187	947,439	117,398	14,674,083	18,256,107	78,177	50,618	9,589	669,293	807,677
Apr-21	2,221,212	551,805	181,710	12,376,262	15,330,989	67,575	32,831	6,639	636,750	743,795
May-21	1,702,148	715,117	134,953	12,828,933	15,381,151	74,896	38,718	7,785	744,269	865,668
Jun-21	1,138,201	520,848	73,906	11,088,523	12,821,478	65,649	45,860	4,682	699,115	815,306
Jul-21	1,323,256	446,832	110,578	10,310,647	12,191,312	72,501	35,621	6,342	660,329	774,793
Aug-21	1,055,652	582,455	130,397	8,306,869	10,075,373	60,909	41,367	8,814	526,547	637,637
Sep-21	1,159,276	609,099	129,904	10,038,727	11,937,005	85,382	68,429	11,435	653,886	819,132
Oct-21	1,153,755	594,054	168,020	9,789,125	11,704,954	86,346	59,591	11,364	639,219	796,520
Nov-21	1,297,142	391,021	149,499	11,674,525	13,512,187	94,652	45,987	8,529	648,210	797,378
Dec-21	1,001,841	1,186,616	140,597	11,886,753	14,215,807	63,041	75,829	5,645	659,803	804,318
TOTAL	86,771,466	38,737,966	20,244,908	420,483,469	566,237,808	3,602,077	2,114,638	746,091	20,808,364	27,271,170

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-20	2,898,979	1,255,867	934,870	9,125,163	14,214,879	137,826	96,035	40,542	564,363	838,766
Feb-20	2,612,370	1,482,095	854,591	8,563,657	13,512,713	110,759	87,190	32,242	535,392	765,583
Mar-20	2,858,559	1,898,911	836,553	8,904,119	14,498,142	104,922	101,540	33,173	495,693	735,328
Apr-20	2,865,235	1,604,592	753,404	7,928,948	13,152,179	119,135	85,209	28,416	454,794	687,554
May-20	2,683,033	1,003,073	483,381	9,243,633	13,413,120	145,382	69,535	29,462	590,351	834,730
Jun-20	2,446,275	1,274,509	679,616	12,187,056	16,587,456	153,982	93,233	28,630	734,369	1,010,214
Jul-20	2,327,354	929,229	654,258	11,723,592	15,634,434	122,042	67,440	30,594	692,881	912,957
Aug-20	2,885,456	965,737	602,209	12,270,529	16,723,930	114,008	56,585	26,662	665,354	862,609
Sep-20	2,759,958	1,311,305	545,808	11,870,827	16,487,899	112,007	54,772	24,409	626,387	817,575
Oct-20	1,170,266	1,614,110	333,422	11,454,599	14,572,397	58,869	58,982	17,031	559,349	694,231
Nov-20	473,510	372,486	207,826	5,194,734	6,248,556	25,978	20,300	6,857	363,785	416,920
Dec-20	414,395	595,040	74,661	4,240,307	5,324,402	27,215	36,578	4,791	322,872	391,456
Jan-21	505,184	926,449	85,441	3,896,822	5,413,896	32,026	41,610	4,835	327,824	406,295
Feb-21	665,309	998,094	144,146	5,150,556	6,958,106	38,384	56,952	6,752	362,064	464,152
Mar-21	591,031	618,699	63,162	5,247,981	6,520,873	30,026	36,699	6,398	333,759	406,882
Apr-21	564,781	177,129	72,851	4,059,957	4,874,718	25,343	20,672	3,991	306,151	356,157
May-21	442,299	181,378	46,319	4,519,932	5,189,928	30,276	21,686	4,028	379,282	435,272
Jun-21	335,834	299,253	33,954	4,488,181	5,157,223	27,490	31,522	3,063	385,387	447,462
Jul-21	338,862	275,306	67,024	4,335,957	5,017,149	28,909	24,474	4,047	368,403	425,833
Aug-21	324,030	352,755	60,145	3,255,200	3,992,130	23,440	24,760	3,957	271,448	323,605
Sep-21	397,314	351,372	53,102	3,992,336	4,794,124	27,907	33,791	4,810	272,943	339,451
Oct-21	327,648	278,394	52,358	3,375,067	4,033,467	26,731	25,513	4,845	251,090	308,179
Nov-21	400,829	133,871	58,953	4,280,984	4,874,637	35,315	25,029	3,725	288,976	353,045
Dec-21	319,191	433,602	67,637	4,111,751	4,932,180	22,912	41,869	2,334	307,385	374,500
TOTAL	31,607,700	19,333,256	7,765,692	163,421,889	222,128,536	1,580,884	1,211,976	355,594	10,460,302	13,608,756

In 2021, the cleared MW volume of up to congestion transactions was comprised of 8.4 percent imports, 8.1 percent exports, 1.3 percent wheeling transactions and 82.1 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority cannot see how the power will flow to the load, which can create loop flows and result in inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM energy market, at the PJM/NYIS Interface regardless of the submitted path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

At the April 10, 2013, PJM Market Implementation Committee (MIC), the MMU presented a problem statement and issue charge to address sham scheduling activities.[73] The expected deliverables from the stakeholder meetings were revisions to the Tariff and PJM business manuals. The topic was discussed at several MIC meetings. While there was stakeholder agreement that sham scheduling activity was inappropriate, consensus on revised tariff and manual language was not achieved. The topic was closed. The MMU clarified that it would continue to monitor transactions for sham scheduling activities and that the MMU could refer market participants for sham scheduling activities.

The MMU monitors for sham scheduling activities on a daily basis. Following the stakeholder discussions in 2013, the net profits obtained from sham scheduling activities fell by 105.4 percent, from net profits of $15.5 million in 2014, to a net loss of $839,891 in 2021. The total number of hours of sham scheduling segments where the MW profile matched exactly across all segments of the path combinations in the same hour fell by 92.2 percent, from 1,898 hours in 2014 to 148 hours in 2021.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/IMO interface pricing point to reflect the actual power flows

73 *See* Market Path/Interface Pricing Point alignment Problem Statement, at: <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Market_Path_Interface_Pricing_Point_Alignment_Problem_Statement_201304010.pdf>.

across both the MISO/PJM and NYISO/PJM interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities.[74] For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market. This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO Interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS Interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In 2021, of the 488 GWh of gross scheduled transactions between PJM and IESO, 474 GWh (97.1 percent) wheeled through MISO (Table 9-25). The MMU recommends that

74 *See* "Sham Scheduling," Presented at the PJM Market Monitoring Unit Advisory Committee (MMUAC) meeting held on December 6, 2013 <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_Sham_Scheduling_20131206.pdf>.

PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[75]

PJM and NYISO Coordinated Interchange Transactions

Coordinated transaction scheduling (CTS) provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated.[76] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price IT SCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for 2021. Table 9-41 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 24.5 percent of the intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $1.74 per MWh. In 11.3 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $61.15 when the price difference was greater than $20.00, and $112.08 when the price difference was greater than -$20.00.

Table 9-41 Differences between forecast and actual PJM/NYIS interface prices: 2021

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	7.4%	$61.15
$10 to $20	7.5%	$14.05
$5 to $10	10.1%	$7.15
$0 to $5	34.5%	$1.74
$0 to -$5	29.1%	$1.52
-$5 to -$10	4.7%	$6.99
-$10 to -$20	2.7%	$14.10
< -$20	3.9%	$112.08

Table 9-42 shows how the accuracy of the IT SCED forecasted LMPs changes as the cases approach real-time. In the final IT SCED results prior to real time, in 60.2 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 57.9 percent in the 135 minute ahead IT SCED results.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: 2021

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	10.1%	$56.78	8.3%	$54.41	4.4%	$50.19	8.3%	$65.31
$10 to $20	9.4%	$14.22	8.8%	$14.12	6.4%	$13.90	8.5%	$14.17
$5 to $10	11.0%	$7.21	11.3%	$7.23	9.6%	$7.18	10.5%	$7.21
$0 to $5	31.2%	$1.88	32.4%	$1.87	30.8%	$1.75	30.4%	$1.81
$0 to -$5	26.7%	$1.64	26.9%	$1.64	33.4%	$1.67	29.8%	$1.61
-$5 to -$10	4.8%	$7.06	5.2%	$7.05	6.8%	$7.03	5.4%	$6.98
-$10 to -$20	2.9%	$14.01	2.9%	$14.04	3.9%	$13.99	3.0%	$14.04
< -$20	3.9%	$105.16	4.2%	$101.66	4.7%	$97.54	4.0%	$104.31

75 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.
76 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

In 12.3 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price difference was $65.31 when the price difference was greater than $20.00, and $104.31 when the price difference was greater than -$20.00.

Table 9-43 and Table 9-44 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-43 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): 2021

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	6.4%	11.8%	0.9%	1.6%	1.0%	4.1%	5.7%	15.0%	6.8%	20.5%	17.7%	8.3%	8.3%
	$10 to $20	4.5%	10.1%	2.6%	4.3%	2.2%	6.1%	9.4%	11.9%	12.4%	16.7%	14.3%	7.8%	8.5%
	$5 to $10	5.6%	9.5%	4.9%	11.2%	6.9%	7.8%	13.7%	12.9%	13.1%	13.1%	14.1%	13.2%	10.5%
	$0 to $5	28.0%	27.1%	34.1%	40.5%	35.0%	38.1%	32.7%	33.9%	25.6%	20.9%	21.7%	27.4%	30.4%
	$0 to -$5	42.1%	24.2%	46.3%	35.2%	43.1%	34.3%	28.9%	19.4%	27.5%	13.5%	15.5%	26.4%	29.8%
	-$5 to -$10	4.0%	5.6%	5.9%	4.3%	7.2%	4.5%	5.2%	2.3%	6.4%	5.9%	6.2%	7.6%	5.4%
	-$10 to -$20	2.5%	4.5%	2.0%	1.8%	2.2%	2.0%	1.7%	1.5%	4.5%	4.6%	4.8%	4.4%	3.0%
	< -$20	7.0%	7.3%	3.3%	1.1%	2.4%	3.0%	2.6%	3.0%	3.6%	4.7%	5.7%	4.9%	4.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	6.8%	11.8%	0.9%	1.4%	1.0%	4.1%	6.5%	9.4%	1.2%	5.0%	4.2%	1.0%	4.4%
	$10 to $20	3.7%	9.8%	2.8%	4.9%	2.4%	6.1%	9.6%	10.7%	5.1%	11.8%	8.7%	1.5%	6.4%
	$5 to $10	5.7%	10.3%	5.3%	11.2%	7.1%	7.5%	13.5%	14.5%	9.7%	13.5%	11.6%	5.1%	9.6%
	$0 to $5	27.9%	26.4%	34.0%	40.7%	34.1%	38.3%	31.0%	34.1%	29.6%	25.2%	22.5%	25.3%	30.8%
	$0 to -$5	42.4%	23.5%	46.1%	34.2%	43.5%	34.3%	29.7%	22.7%	35.8%	21.9%	25.1%	40.8%	33.4%
	-$5 to -$10	3.8%	6.1%	6.1%	4.3%	7.5%	4.7%	5.4%	3.2%	7.6%	8.8%	11.3%	13.0%	6.8%
	-$10 to -$20	2.6%	4.3%	1.8%	1.8%	1.8%	1.9%	1.5%	1.9%	6.3%	7.8%	8.2%	7.1%	3.9%
	< -$20	7.1%	7.8%	3.1%	1.4%	2.4%	3.1%	2.8%	3.5%	4.7%	6.0%	8.5%	6.1%	4.7%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	14.1%	15.2%	8.6%	9.5%	5.4%	11.7%	10.8%	9.6%	2.4%	6.8%	4.1%	1.6%	8.3%
	$10 to $20	8.3%	10.2%	8.0%	10.9%	7.1%	7.1%	12.4%	11.6%	6.6%	12.8%	8.8%	2.3%	8.8%
	$5 to $10	7.3%	10.5%	10.7%	14.9%	10.4%	8.2%	15.2%	14.4%	8.9%	15.4%	12.6%	6.7%	11.3%
	$0 to $5	25.6%	24.0%	39.5%	39.4%	40.0%	39.3%	26.2%	29.8%	33.1%	30.7%	28.6%	32.2%	32.4%
	$0 to -$5	32.5%	22.2%	27.2%	20.8%	29.9%	26.4%	25.8%	24.7%	34.0%	18.0%	23.2%	36.9%	26.9%
	-$5 to -$10	3.6%	5.5%	2.6%	2.6%	3.9%	3.3%	5.3%	4.4%	6.2%	6.1%	9.3%	9.7%	5.2%
	-$10 to -$20	2.1%	5.1%	1.0%	1.1%	1.3%	1.3%	1.7%	2.0%	4.4%	5.1%	5.9%	4.7%	2.9%
	< -$20	6.6%	7.4%	2.4%	0.8%	2.0%	2.8%	2.6%	3.5%	4.3%	5.2%	7.5%	6.0%	4.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	13.8%	15.5%	8.2%	9.2%	5.7%	11.4%	11.4%	15.9%	5.1%	15.5%	7.4%	2.5%	10.1%
	$10 to $20	8.4%	10.8%	8.1%	11.7%	6.7%	7.4%	13.1%	12.3%	7.8%	14.6%	9.0%	2.9%	9.4%
	$5 to $10	7.4%	10.0%	10.7%	14.5%	10.6%	8.8%	13.8%	11.9%	10.2%	14.3%	12.8%	6.8%	11.0%
	$0 to $5	25.0%	23.6%	39.5%	39.4%	39.6%	39.0%	25.6%	25.7%	31.0%	27.5%	26.4%	32.1%	31.2%
	$0 to -$5	33.1%	21.9%	27.6%	20.8%	30.2%	26.1%	26.3%	24.2%	33.3%	15.0%	23.9%	37.4%	26.7%
	-$5 to -$10	3.3%	5.4%	2.6%	2.6%	4.0%	3.1%	5.5%	4.8%	5.1%	5.2%	7.9%	8.1%	4.8%
	-$10 to -$20	2.5%	5.4%	0.9%	1.0%	1.3%	1.5%	1.8%	1.8%	3.9%	3.8%	5.7%	4.9%	2.9%
	< -$20	6.5%	7.4%	2.5%	0.8%	2.0%	2.7%	2.5%	3.4%	3.7%	4.0%	6.8%	5.4%	3.9%

Table 9-44 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): 2021

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$44.95	$73.81	$39.78	$31.47	$51.34	$75.21	$44.71	$58.25	$65.81	$56.80	$95.85	$60.29	$65.31
	$10 to $20	$14.69	$14.35	$14.07	$13.09	$13.33	$13.76	$14.03	$14.26	$14.09	$14.45	$14.31	$14.12	$14.17
	$5 to $10	$7.01	$7.26	$6.78	$7.00	$6.99	$7.36	$7.12	$7.25	$7.22	$7.41	$7.50	$7.13	$7.21
	$0 to $5	$1.33	$1.80	$1.33	$1.81	$1.71	$1.59	$1.92	$1.72	$2.05	$2.43	$2.34	$2.21	$1.81
	$0 to -$5	$1.41	$1.51	$1.40	$1.44	$1.65	$1.55	$1.54	$1.30	$1.99	$2.13	$1.98	$2.03	$1.61
	-$5 to -$10	$6.83	$7.19	$6.85	$6.78	$6.78	$6.93	$6.73	$7.25	$7.16	$7.10	$7.06	$7.18	$6.98
	-$10 to -$20	$13.92	$13.85	$13.66	$14.90	$13.45	$14.82	$14.53	$13.22	$14.20	$13.88	$14.29	$13.90	$14.04
	< -$20	$145.03	$157.03	$161.81	$45.06	$104.99	$95.98	$88.21	$111.31	$67.44	$56.96	$78.20	$60.02	$104.31

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$45.33	$74.95	$43.12	$32.04	$48.27	$74.92	$44.88	$44.68	$37.15	$31.39	$30.46	$28.11	$50.19
	$10 to $20	$14.78	$14.21	$14.13	$13.88	$13.65	$13.79	$13.63	$14.16	$13.46	$13.76	$13.80	$13.44	$13.90
	$5 to $10	$7.10	$7.33	$6.92	$7.02	$6.84	$7.38	$7.07	$7.27	$7.34	$7.28	$7.37	$6.94	$7.18
	$0 to $5	$1.39	$1.73	$1.36	$1.80	$1.68	$1.58	$1.95	$1.80	$1.84	$2.13	$2.13	$1.82	$1.75
	$0 to -$5	$1.43	$1.46	$1.43	$1.46	$1.66	$1.59	$1.56	$1.44	$1.88	$2.06	$2.20	$2.09	$1.67
	-$5 to -$10	$6.86	$7.20	$6.80	$6.76	$6.85	$6.94	$6.78	$6.99	$7.22	$7.18	$7.23	$7.10	$7.03
	-$10 to -$20	$14.04	$13.61	$14.19	$14.21	$13.74	$14.89	$14.24	$13.97	$13.92	$14.19	$13.94	$13.76	$13.99
	< -$20	$144.06	$149.23	$166.30	$41.75	$102.57	$93.93	$83.32	$113.53	$62.22	$55.14	$72.23	$60.32	$97.54

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$47.82	$71.96	$49.65	$28.90	$76.52	$101.55	$42.77	$40.83	$32.44	$38.20	$35.58	$34.15	$54.41
	$10 to $20	$14.46	$14.46	$13.99	$14.42	$13.93	$14.14	$14.17	$14.10	$13.59	$13.80	$14.01	$14.43	$14.12
	$5 to $10	$7.17	$7.45	$7.04	$7.22	$7.27	$7.01	$7.44	$7.35	$7.23	$7.27	$7.15	$6.85	$7.23
	$0 to $5	$1.73	$1.79	$1.68	$1.94	$1.87	$1.87	$1.88	$1.91	$1.69	$2.10	$2.15	$1.83	$1.87
	$0 to -$5	$1.53	$1.56	$1.41	$1.45	$1.62	$1.63	$1.70	$1.56	$1.50	$2.09	$2.01	$1.80	$1.64
	-$5 to -$10	$6.88	$7.15	$6.62	$6.93	$6.86	$6.80	$6.83	$6.94	$7.12	$7.24	$7.30	$7.12	$7.05
	-$10 to -$20	$14.62	$14.25	$14.92	$13.14	$14.12	$15.00	$13.80	$14.38	$13.93	$13.90	$13.93	$13.62	$14.04
	< -$20	$147.42	$153.79	$200.12	$43.55	$103.17	$95.05	$90.85	$116.32	$62.57	$56.40	$74.33	$58.79	$101.66

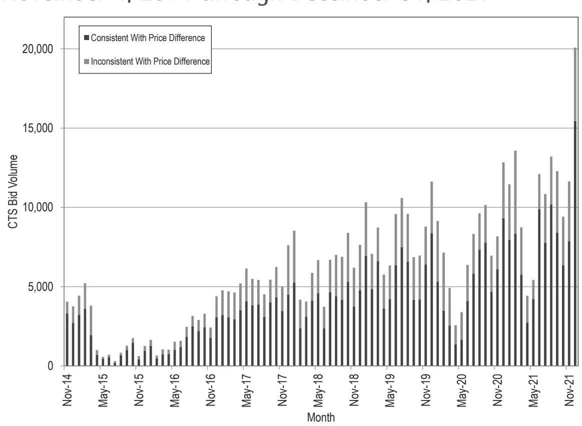
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$48.55	$73.92	$50.91	$29.52	$76.18	$107.48	$42.40	$42.03	$42.83	$57.54	$54.03	$45.97	$56.78
	$10 to $20	$14.52	$14.49	$14.21	$14.34	$14.36	$14.40	$14.00	$14.58	$13.46	$14.26	$13.91	$13.36	$14.22
	$5 to $10	$7.40	$7.27	$7.05	$7.16	$7.33	$6.99	$7.32	$7.22	$7.28	$7.23	$7.18	$7.10	$7.21
	$0 to $5	$1.71	$1.73	$1.69	$1.96	$1.88	$1.97	$1.94	$1.98	$1.71	$2.11	$2.10	$1.79	$1.88
	$0 to -$5	$1.54	$1.54	$1.41	$1.49	$1.59	$1.68	$1.74	$1.67	$1.47	$1.80	$1.96	$1.81	$1.64
	-$5 to -$10	$6.85	$7.34	$6.76	$6.85	$6.77	$6.83	$6.94	$6.99	$7.27	$7.11	$7.47	$6.94	$7.06
	-$10 to -$20	$14.68	$14.30	$14.44	$13.31	$14.20	$14.90	$13.84	$14.31	$13.96	$13.83	$13.75	$13.57	$14.01
	< -$20	$150.33	$153.71	$194.79	$43.92	$105.27	$98.11	$90.31	$115.47	$60.73	$63.15	$74.19	$60.37	$105.16

The NYISO uses PJM's IT SCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the IT SCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through December 31, 2021, 521,993 15 minute CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 164,113 (31.4 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 31.4 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 68.6 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-14 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-14 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-14 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through December 31, 2021



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO Interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/MISO interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for 2021. Table 9-45 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 33.0 percent of all intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $1.76. In 12.2 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $52.65 when the price difference was greater than $20.00, and $78.98 when the price difference was greater than -$20.00.

Table 9-45 Differences between forecast and actual PJM/MISO interface prices: 2021

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	8.1%	$52.65
$10 to $20	8.5%	$14.14
$5 to $10	9.9%	$7.20
$0 to $5	33.0%	$1.76
$0 to -$5	29.0%	$1.57
-$5 to -$10	4.6%	$6.97
-$10 to -$20	2.8%	$13.98
< -$20	4.1%	$78.98

Table 9-46 shows how the accuracy of the IT SCED forecasted LMPs change as the cases approach real-time. In the final IT SCED results prior to real-time, in 58.4 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 57.8 percent in the 135 minute ahead IT SCED results.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: 2021

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	10.3%	$49.27	8.4%	$40.87	6.0%	$40.83	8.5%	$51.91
$10 to $20	9.3%	$14.34	9.1%	$14.30	8.9%	$14.00	8.9%	$14.17
$5 to $10	9.7%	$7.17	10.1%	$7.21	9.7%	$7.20	10.2%	$7.21
$0 to $5	29.1%	$1.86	29.8%	$1.86	29.7%	$1.82	29.5%	$1.81
$0 to -$5	28.7%	$1.70	29.1%	$1.71	31.0%	$1.71	28.9%	$1.70
-$5 to -$10	5.4%	$7.00	5.4%	$6.99	6.0%	$6.99	5.6%	$7.03
-$10 to -$20	3.2%	$13.94	3.3%	$13.88	3.7%	$14.00	3.6%	$13.92
< -$20	4.4%	$81.51	4.7%	$79.94	4.9%	$77.77	4.9%	$75.79

In 13.4 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $51.91 when the price difference was greater than $20.00, and $75.79 when the price difference was greater than -$20.00.

Table 9-47 and Table 9-48 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-47 Monthly differences between forecast and actual PJM/MISO interface prices (percent of intervals): 2021

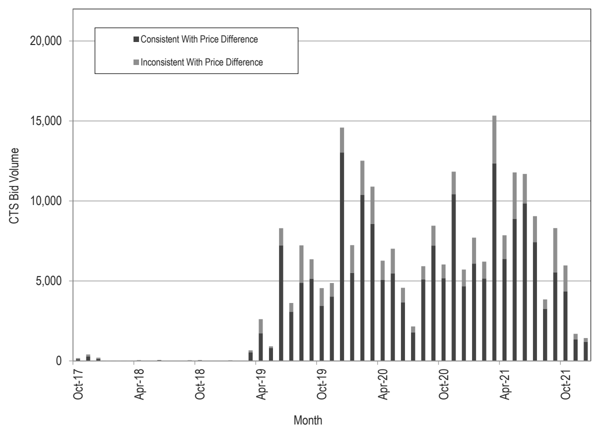
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	0.9%	9.9%	1.7%	5.1%	0.9%	6.4%	7.6%	16.4%	8.8%	24.2%	16.5%	3.8%	8.5%
	$10 to $20	2.4%	4.7%	3.5%	12.1%	6.9%	9.4%	10.0%	11.6%	11.6%	14.5%	14.7%	5.8%	8.9%
	$5 to $10	3.8%	6.5%	7.5%	14.0%	9.8%	9.0%	14.3%	13.6%	10.1%	10.2%	12.9%	10.0%	10.2%
	$0 to $5	36.9%	32.9%	37.7%	33.1%	34.1%	35.3%	31.1%	32.6%	21.8%	14.8%	14.9%	28.4%	29.5%
	$0 to -$5	48.4%	31.5%	40.1%	26.3%	37.4%	29.1%	27.5%	18.9%	27.3%	13.0%	15.0%	31.6%	28.9%
	-$5 to -$10	3.6%	5.3%	4.3%	4.3%	4.6%	3.6%	4.7%	2.1%	9.3%	7.6%	7.9%	9.8%	5.6%
	-$10 to -$20	2.0%	2.7%	1.8%	2.0%	2.9%	2.5%	1.8%	1.5%	5.5%	7.2%	8.2%	5.2%	3.6%
	< -$20	2.1%	6.6%	3.5%	3.0%	3.4%	4.8%	3.0%	3.3%	5.6%	8.5%	10.1%	5.4%	4.9%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	1.0%	9.6%	1.7%	5.5%	1.0%	6.0%	7.7%	10.2%	4.6%	13.5%	10.3%	2.0%	6.0%
	$10 to $20	2.6%	5.4%	3.9%	12.7%	7.5%	9.5%	10.5%	11.8%	9.1%	16.8%	13.1%	3.5%	8.9%
	$5 to $10	3.6%	6.6%	7.1%	12.5%	9.5%	9.2%	13.5%	14.2%	9.5%	12.0%	12.7%	6.1%	9.7%
	$0 to $5	36.4%	32.2%	37.4%	32.2%	32.9%	35.8%	31.1%	32.7%	24.8%	17.8%	16.3%	27.2%	29.7%
	$0 to -$5	49.0%	31.7%	40.5%	27.9%	38.1%	28.5%	27.8%	22.8%	31.9%	16.8%	17.9%	38.8%	31.0%
	-$5 to -$10	3.4%	5.0%	4.0%	4.3%	5.0%	3.9%	4.9%	3.0%	9.1%	7.6%	10.6%	11.2%	6.0%
	-$10 to -$20	2.0%	3.0%	2.0%	2.2%	2.6%	2.4%	1.5%	1.6%	5.5%	7.3%	9.0%	5.3%	3.7%
	< -$20	2.1%	6.6%	3.4%	2.9%	3.4%	4.7%	3.0%	3.7%	5.5%	8.2%	10.1%	5.9%	4.9%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	2.3%	11.4%	3.5%	13.2%	5.1%	11.5%	10.4%	11.2%	5.5%	15.5%	9.8%	2.3%	8.4%
	$10 to $20	3.0%	4.7%	5.9%	12.6%	10.2%	8.2%	12.4%	12.1%	8.3%	15.6%	12.9%	3.0%	9.1%
	$5 to $10	3.9%	6.6%	8.2%	11.3%	8.9%	8.1%	14.4%	14.1%	10.5%	14.2%	15.2%	6.2%	10.1%
	$0 to $5	37.5%	31.6%	37.2%	29.7%	32.4%	33.4%	26.6%	28.1%	28.5%	21.5%	19.0%	32.1%	29.8%
	$0 to -$5	46.5%	30.1%	34.8%	23.5%	32.5%	27.6%	26.5%	25.2%	31.4%	15.3%	17.3%	37.7%	29.1%
	-$5 to -$10	3.0%	5.0%	4.3%	4.8%	5.3%	3.8%	5.2%	3.6%	6.4%	5.9%	9.0%	9.0%	5.4%
	-$10 to -$20	1.8%	4.0%	2.4%	2.3%	2.5%	2.5%	1.6%	1.8%	4.3%	5.4%	7.2%	3.9%	3.3%
	< -$20	2.0%	6.6%	3.6%	2.6%	3.1%	4.9%	2.9%	3.7%	5.1%	6.6%	9.6%	5.8%	4.7%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	2.2%	11.8%	3.5%	13.3%	5.0%	11.5%	11.6%	16.1%	8.3%	24.2%	13.7%	3.0%	10.3%
	$10 to $20	3.0%	4.7%	6.0%	12.5%	10.7%	8.8%	11.6%	11.8%	8.9%	15.7%	13.9%	3.3%	9.3%
	$5 to $10	4.0%	6.2%	8.3%	12.3%	9.0%	8.2%	13.7%	11.1%	11.0%	12.6%	13.7%	6.0%	9.7%
	$0 to $5	37.5%	31.7%	36.9%	28.3%	31.5%	33.1%	26.0%	25.8%	26.7%	20.3%	17.9%	33.7%	29.1%
	$0 to -$5	46.4%	30.0%	35.1%	23.0%	32.6%	27.2%	27.1%	25.1%	30.7%	12.5%	17.3%	36.7%	28.7%
	-$5 to -$10	3.1%	5.1%	4.4%	5.5%	5.7%	3.8%	5.4%	4.6%	5.4%	5.0%	8.3%	8.4%	5.4%
	-$10 to -$20	1.7%	3.9%	2.2%	2.3%	2.4%	2.7%	1.8%	2.2%	4.2%	4.3%	6.9%	3.6%	3.2%
	< -$20	2.1%	6.6%	3.6%	2.7%	3.1%	4.8%	2.7%	3.4%	4.8%	5.5%	8.4%	5.4%	4.4%

Table 9-48 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): 2021

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$31.30	$60.02	$125.91	$29.41	$25.20	$48.24	$42.00	$55.84	$30.94	$47.81	$61.54	$81.10	$51.91
	$10 to $20	$13.55	$13.93	$13.50	$13.83	$13.96	$13.53	$14.01	$14.50	$14.35	$14.69	$14.50	$14.17	$14.17
	$5 to $10	$6.84	$7.06	$7.02	$7.26	$7.19	$7.55	$7.18	$7.19	$7.33	$7.41	$7.25	$7.00	$7.21
	$0 to $5	$1.45	$1.55	$1.64	$2.03	$1.71	$1.69	$1.89	$1.68	$2.08	$2.26	$2.45	$2.12	$1.81
	$0 to -$5	$1.36	$1.48	$1.62	$1.74	$1.68	$1.50	$1.55	$1.24	$2.07	$2.35	$2.35	$2.23	$1.70
	-$5 to -$10	$6.88	$7.05	$6.88	$6.75	$6.84	$6.83	$6.82	$7.10	$7.15	$7.19	$7.33	$7.03	$7.03
	-$10 to -$20	$14.15	$13.83	$14.19	$13.51	$13.76	$14.50	$13.98	$13.77	$14.35	$14.08	$13.80	$13.34	$13.92
	< -$20	$61.67	$58.63	$113.80	$49.22	$88.55	$78.41	$76.45	$115.61	$76.15	$65.92	$80.07	$62.95	$75.79
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$30.86	$60.30	$126.02	$29.56	$25.38	$48.75	$43.23	$39.73	$28.21	$32.85	$30.73	$31.33	$40.83
	$10 to $20	$14.14	$14.39	$13.55	$13.84	$13.84	$13.44	$13.93	$14.14	$14.02	$14.47	$14.05	$13.65	$14.00
	$5 to $10	$6.86	$7.21	$6.99	$7.18	$7.10	$7.49	$7.10	$7.20	$7.31	$7.46	$7.27	$6.86	$7.20
	$0 to $5	$1.45	$1.51	$1.71	$2.11	$1.76	$1.70	$1.92	$1.80	$2.07	$2.16	$2.39	$1.77	$1.82
	$0 to -$5	$1.38	$1.44	$1.66	$1.72	$1.69	$1.56	$1.58	$1.39	$1.97	$2.08	$2.29	$2.13	$1.71
	-$5 to -$10	$6.78	$6.72	$6.85	$6.80	$6.89	$7.00	$6.90	$6.98	$7.11	$7.27	$7.27	$6.85	$6.99
	-$10 to -$20	$14.11	$13.59	$13.73	$13.98	$14.15	$14.90	$14.18	$13.89	$14.12	$14.21	$13.89	$13.53	$14.00
	< -$20	$60.66	$59.71	$114.46	$50.07	$88.43	$79.26	$77.03	$120.27	$78.72	$68.87	$84.07	$61.09	$77.77
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$27.95	$56.15	$75.15	$32.10	$27.20	$49.52	$40.78	$36.93	$31.79	$41.48	$33.34	$37.72	$40.87
	$10 to $20	$14.55	$14.67	$13.96	$14.49	$14.20	$14.61	$14.77	$14.20	$14.04	$14.10	$14.06	$13.98	$14.30
	$5 to $10	$6.97	$7.13	$6.93	$7.13	$7.27	$7.06	$7.28	$7.30	$7.25	$7.29	$7.33	$7.08	$7.21
	$0 to $5	$1.60	$1.54	$1.86	$2.08	$1.77	$1.86	$1.90	$1.87	$1.89	$2.07	$2.29	$1.87	$1.86
	$0 to -$5	$1.48	$1.53	$1.77	$1.80	$1.64	$1.71	$1.67	$1.55	$1.61	$2.02	$2.29	$1.92	$1.71
	-$5 to -$10	$6.84	$6.98	$6.78	$7.00	$6.91	$6.78	$6.93	$7.12	$7.10	$7.07	$7.20	$6.95	$6.99
	-$10 to -$20	$13.97	$13.59	$12.92	$14.11	$14.36	$14.30	$13.74	$14.14	$14.13	$13.84	$13.89	$13.74	$13.88
	< -$20	$60.91	$61.47	$114.68	$51.01	$92.86	$75.71	$76.15	$119.68	$79.50	$76.91	$86.99	$62.10	$79.94
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$26.98	$56.37	$77.07	$32.16	$27.54	$51.30	$39.87	$36.59	$42.60	$71.49	$49.75	$52.55	$49.27
	$10 to $20	$14.42	$14.23	$14.12	$14.60	$14.14	$14.69	$14.52	$14.51	$13.87	$14.47	$14.04	$14.04	$14.34
	$5 to $10	$6.93	$7.18	$7.05	$7.12	$7.20	$6.94	$7.27	$7.17	$7.17	$7.29	$7.34	$7.03	$7.17
	$0 to $5	$1.57	$1.60	$1.84	$2.06	$1.81	$1.87	$1.94	$1.94	$1.82	$2.18	$2.33	$1.79	$1.86
	$0 to -$5	$1.51	$1.54	$1.81	$1.78	$1.63	$1.74	$1.70	$1.59	$1.60	$1.92	$2.21	$1.80	$1.70
	-$5 to -$10	$7.07	$7.11	$7.00	$6.88	$6.75	$6.80	$7.06	$6.78	$7.28	$7.31	$7.18	$6.76	$7.00
	-$10 to -$20	$13.81	$14.02	$13.25	$14.16	$14.09	$14.77	$14.58	$14.46	$13.63	$13.91	$13.79	$13.57	$13.94
	< -$20	$61.55	$61.65	$115.73	$50.20	$92.93	$77.63	$79.96	$127.11	$76.64	$81.62	$90.52	$63.34	$81.51

CTS transactions were evaluated for each interval. From October 3, 2017, through December 31, 2021, 234,163 CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 44,813 (19.1 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 19.1 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 80.9 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 9-15 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 9-15 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-15 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through December 31, 2021



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-49 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only two months (January 2016 and February 2019). In both months, there was negative uncollected congestion. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in both January 2016 and February 2019.

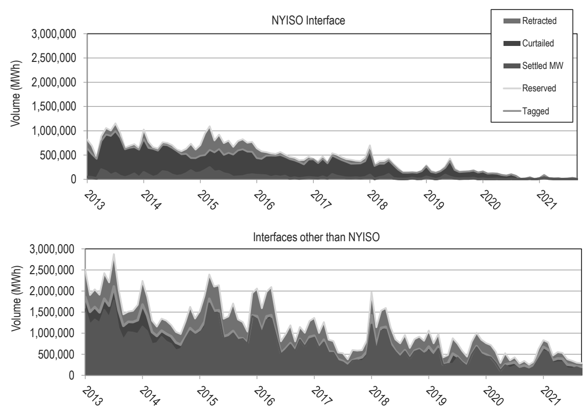
Table 9-49 Monthly uncollected congestion charges: January 2010 through December 2021

Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0	$0	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0	($69,992)	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0	$0	$0	$0
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0	($69,992)	$0	$0

Spot Imports

Figure 9-16 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through December 31, 2021. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service. This area may also represent hoarding opportunities, particularly at the NYISO Interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding the transmission from other market participants that may wish to use it. The green shaded area represents the total settled MWh of spot import service. Figure 9-16 shows that while there are proportionally fewer retracted MWh on the NYISO Interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.[77]

Figure 9-16 Spot import service use: January 2013 through December 2021



The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm point to point willing to pay congestion imports and exports) at all PJM interfaces.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible for PJM system operators

77 See the *2018 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions," for a more complete discussion of the history of spot import transmission service.

to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[78] These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point to point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, are dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports

78 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764. See *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, order on reh'g, Order No. 764-A, 141 FERC ¶ 61231 (2012).

and exports. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is based on the assumption that the available generation in the PJM system can only move 1,000 MW over any 15 minute period, although there is no supporting analysis. As an example of how the ramp limit works, if at 0800 the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intrahour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with relatively little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[79] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[80]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[81]

MISO Multi-Value Project Usage Rate (MUR)

MISO defines a multi-value project (MVP) to be a project which, according to MISO, enables the reliable and economic delivery of energy in support of public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value.[82] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[83] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[84] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

On June 7, 2014, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP Order and MVP Rehearing Order.[85] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[86] The Seventh Circuit highlighted the fact that at the time of the Commission's decision to prohibit rate pancaking on transactions between MISO and PJM, all of MISO's transmission projects were local and provided only local benefits.[87]

79 *Id.* at P 51.
80 See *Id.* at P 12.

81 See joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.
82 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>.
83 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
84 133 FERC ¶ 61,221; *order on reh'g*, 137 FERC ¶ 61,074 (2011).
85 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
86 *Id.* at 780.
87 *Id.* at 779.

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[88] The July 13th Order noted that in light of "the development of large scale wind generation capable of serving both MISO's and its neighbors' energy policy requirements in the western areas of MISO; the reported need of PJM entities to access those resources; and the reported need for MISO to build new transmission facilities to deliver the output of those resources within MISO for export… it is appropriate to allow MISO to assess the MVP usage charge for transmission service used to export to PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions."[89]

The policy rationale for permitting MISO to impose transmission costs on PJM market participants without clear criteria is weak and results in pancaking of rates. The impact is expected to increase.

Table 9-50 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2021 through 2040.[90] As shown in Table 9-4, there were 2,391.2 GWh of imports from MISO in 2021. At the 2021 MUR of $1.67 per MWh, PJM market participants paid $3.9 million towards the costs of MISO's multi value projects. It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-50 MISO projected multi value project usage rate: 2021 through 2040

Year	Total Indicative MVP Usage Rate ($/MWh)
2021	$1.67
2022	$1.65
2023	$1.64
2024	$1.77
2025	$1.75
2026	$1.73
2027	$1.72
2028	$1.70
2029	$1.69
2030	$1.67
2031	$1.65
2032	$1.64
2033	$1.62
2034	$1.61
2035	$1.59
2036	$1.58
2037	$1.56
2038	$1.55
2039	$1.53
2040	$1.52

88 156 FERC ¶ 61,034 (2016).
89 *Id.* at P 55.
90 See MISO, "Schedule 26A Indicative Annual Charges," (August 5, 2020) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.

Ancillary Service Markets

FERC defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve–synchronized reserve service; and operating reserve–supplemental reserve service.[1] PJM provides scheduling, system control and dispatch, and reactive on a cost basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] Although not defined by FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of formula rates.

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market, the PJM DASR Market, and the PJM Regulation Market in 2021.

Table 10-1 The tier 2 synchronized reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require cost-based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately overcompensated when the nonsynchronized reserve market clears with a nonzero price.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the real-time energy market.

Table 10-2 The day-ahead scheduling reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Mixed	
Market Performance	**Competitive**	**Mixed**

- The DASR market structure was evaluated as not competitive because the DASR market failed the three pivotal supplier (TPS) test in 94 percent of the intervals in which the price was greater than $0.01 per MWh.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. The day-ahead scheduling reserve market clearing price was above $0 in 16.9 percent of hours in 2021. In 98.6 percent of hours when the clearing price was above $0, the clearing price was the offer price of the marginal unit. In the remaining 1.4 percent of hours, the price included lost opportunity cost.
- Market design was evaluated as mixed because the DASR product does not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised.

Table 10-3 The regulation market results were not competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 85.9 percent of the hours in 2021.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in 2021 because market power mitigation requires competitive offers when the three pivotal supplier test is failed,

although the inclusion of a positive margin raises questions.

- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[3]

PJM determines the primary reserve requirement based on the most severe single contingency plus 190 MW in every approved RT SCED case. Every real-time market solution calculates the available tier 1 synchronized reserve. The required synchronized reserve and nonsynchronized reserve are calculated and dispatched in every real-time market solution, and there are associated clearing prices (SRMCP and NSRMCP) assigned every five minutes. Scheduled resources are credited based on a dispatched assignment and a five minute clearing price.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the most severe single contingency plus 190 MW. In 2021, the average primary reserve requirement was 2,449.6 MW in the RTO Zone and 2,436.4 in the MAD Subzone.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators and demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes in response to a PJM declared synchronized reserve event. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In 2021, there was an average hourly supply of 1,563.7 MW of tier 1 available in the RTO Zone and an average hourly supply of 788.2 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each real-time dispatch solution as the most severe single contingency plus 190 MW within both the RTO Zone and the MAD Subzone.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid for increasing its output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[4] This is the Synchronized Energy Premium Price.
- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the synchronized energy premium price of $50 per MWh. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized

3 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 40 (Dec. 15, 2021).

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 117 (Nov. 1, 2021).

reserve market clearing price rises above zero. This requirement is unnecessary and inconsistent with efficient markets. This rule has a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, $2,197,514 in 2017, $4,732,025 in 2018, $3,217,178 in 2019, $3,320,726 in 2020, and $7,354,224 in 2021. The nonsynchronized reserve market clearing price was above $0 in 2,015 intervals (1.9 percent of intervals) in 2020, none of which were during a spinning event. In 2021, the nonsynchronized reserve market clearing price was above $0 in 2.9 percent of all intervals resulting in a net payment of $7,364,936.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that may incur costs to be synchronized, and that have an obligation to respond to PJM declared synchronized reserve events. Tier 2 synchronized reserve is penalized for failure to respond to a PJM declared synchronized reserve event. In PJM the required amount of synchronized reserve is defined to be no less than the largest single contingency, and 10 minute primary reserve as no less than 150 percent of the largest single contingency, plus 190 MW. This is stricter than the NERC standard of the greater of 80 percent of the largest single contingency or 900 MW.[5]

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses the tier 2 synchronized reserve market to satisfy the balance of the requirement. The tier 2 synchronized reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In 2021, the supply of daily offered and eligible tier 2 synchronized reserve was 36,355.7 MW in the RTO Zone of which 4,606.9 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,697.1 MW in the RTO Reserve Zone and 1,696.5 in the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 274.1 MW in the MAD Subzone and 720.5 MW in the RTO.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in 2021.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 3460 which is classified as highly concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve, unless the unit type is exempt. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost which is calculated by PJM. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner. Demand resources offering into the tier 2 market are also subject to an offer cap of $7.50 plus costs. Cost may include shutdown costs for demand response.[6]

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the MAD Subzone was $7.32 per MW in 2021. The weighted average price for tier 2 synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $8.87 per MW in 2021.

Nonsynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. Generation owners do

5 NERC (June 2, 2020) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

6 Ref. PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 117 (Nov. 1, 2021), para. 4.2.1, p. 92

not submit supply offers for nonsynchronized reserve. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less (based on offer parameters), and on the resource opportunity costs calculated by PJM.

Market Structure

- **Supply.** In 2021, the average supply of eligible and available nonsynchronized reserve was 1,414.6 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[7]
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 99.96 percent of intervals where the price was above $0.01 in 2021.

Market Conduct

- **Offers.** Generation owners do not submit supply offers. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all intervals in the RTO Reserve Zone was $0.31 per MW in 2021.

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve in the day-ahead market as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but is not required to maintain this level of secondary reserve in real time.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The PJM Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[8] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

Market Structure

- **Supply.** The DASR market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all resources that can provide energy within 30 minutes of a request from PJM Dispatch.
- **Demand.** The DASR requirement is the sum of the PJM requirement and the Dominion requirement based on the VACAR reserve sharing agreement. It is calculated every year for the period November 1 through October 31. For November 1, 2020, through October 31, 2021, the DASR requirement was 4.75 percent of peak load forecast. For November 1, 2021, through October 31, 2022, the DASR requirement is 4.40 percent of peak load forecast. The average hourly DASR MW purchased in 2021 was 4,389.5 MW, a reduction from the 4,611.6 hourly MW in 2020.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In 2021, 45.3 percent of daily unit offers were above $0.00 and 17.8 percent of daily unit offers were above $5.

7 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 117 (Nov. 1, 2021). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

8 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 117 (Nov. 1, 2021).

- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in 2021.

Market Performance

- **Price.** In 2021, the MW weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.27. The MW weighted average for all hours including hours when the price was $0 was $0.24.

Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp rates. The RegD signal is designed for energy limited resources with fast ramp rates. In the regulation market RegD MW are converted to effective MW using a marginal rate of technical substitution (MRTS), called a marginal benefit factor (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the regulation market.

Market Structure

- **Supply.** In 2021, the average hourly offered supply of regulation for nonramp hours was 740.8 performance adjusted MW (744.9 effective MW). This was an increase of 19.9 performance adjusted MW (an increase of 23.7 effective MW) from 2020. In 2021, the average hourly offered supply of regulation for ramp hours was 1,066.4 performance adjusted MW (1,094.9 effective MW). This was an increase of 49.0 performance adjusted MW (an increase of 36.0 effective MW) from 2020, when the average hourly offered supply of regulation was 1,017.4 performance adjusted MW (1,058.9 effective MW).
- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 481.6 hourly average performance adjusted actual MW in 2021. This is an increase of 10.4 performance adjusted actual MW from 2020, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 492.0 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 707.3 hourly average performance adjusted actual MW in 2021. This is an increase of 4.9 performance adjusted actual MW from 2020, where the average hourly regulation cleared MW for ramp hours were 702.5 performance adjusted actual MW.

  The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.51 in 2021 (1.45 in 2020). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.54 in 2021 (1.47 in 2020).
- **Market Concentration.** In 2021, the three pivotal supplier test was failed in 85.9 percent of hours. In 2021, the actual MW weighted average HHI of RegA resources was 2215 which is highly concentrated and the weighted average HHI of RegD resources was 1585 which is moderately concentrated. The weighted average HHI of all resources was 1205, which is moderately concentrated.

Market Conduct

- Offers. Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or

RegD.[9] In 2021, there were 237 resources following the RegA signal and 53 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $26.00 per MW of regulation in 2021, an increase of $12.45 per MW, or 91.9 percent, from the weighted average clearing price of $13.55 per MW in 2020. The weighted average cost of regulation in 2021 was $31.49 per MW of regulation, an increase of 88.2 percent, from the weighted average cost of $16.73 per MW in 2020.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW.
- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[10]

In 2021, total black start charges were $68.0 million, including $67.6 million in revenue requirement charges and $0.3 million in uplift charges. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive payment. Black start uplift charges are paid to units scheduled in the day-ahead energy market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in 2021 ranged from $43,630 in the BGE Zone to $19,803,649 in the AEP Zone.

CRF values are a key determinant of total payments to black start units. The CRF values in PJM tariff tables should have been changed for both black start and the capacity market when the tax laws changed in December 2017. As a result, CRF values have overcompensated black start units since the changes to the tax code.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVAr and MW. The current rules permit double recovery of some fixed costs.

Reactive capability charges are based on FERC approved filings that permit recovery based on an outdated cost of service approach.[11] All capacity costs of generators should be incorporated in the capacity market. The nonmarket cost of service approach to reactive capability payments should be eliminated. Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Total reactive charges increased 6.19 percent from $346.4 million in 2020 to $367.8 million in 2021. Reactive capability charges increased 6.06 percent from $346.0 million in 2020 to $367.0 million in 2021. Total reactive service charges in 2021 ranged from $0 in the REC and OVEC Zones, to $49.2 million in the AEP Zone.

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures

9 See the *2019 State of the Market Report for PJM*, Vol. II, Appendix F "Ancillary Services Markets."
10 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.
11 OATT Schedule 2.

to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[12] PJM filed revisions in compliance with Order No. 842 that incorporated the pro forma agreements into its market rules.[13]

The PJM Tariff requires that all new generator interconnection customers (Nuclear Regulatory Commission regulated facilities are exempt from this provision) have hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output in a direction to correct for frequency deviations. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 deadband.[14] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events remains under evaluation. A frequency event is declared when the frequency goes outside 60 Hz +/- 40 mHz for 60 continuous seconds. The NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to -259.3 MW/0.1 Hz and has selected twelve frequency events between December 1, 2020, and November 30, 2021, to evaluate.

As a balancing authority, PJM requires all generators to be capable of providing primary frequency response and to operate with primary frequency response controls enabled. PJM does monitor primary frequency response during NERC identified frequency events for all resources 50 MW or greater. Exclusions to PJM monitoring include nuclear plants, offline units, units with no available headroom, units assigned to regulation, and units with a current outage ticket in eDART.

Ancillary Services Costs per MWh of Load

Table 10-4 shows PJM ancillary services costs for 1999 through 2021, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh.[15] The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

Table 10-4 History of ancillary services costs per MWh of load: 1999 through 2021[16 17]

Year	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.15	$0.23	$0.26	$0.00	$0.64
2000	$0.39	$0.26	$0.29	$0.00	$0.94
2001	$0.53	$0.71	$0.22	$0.00	$1.46
2002	$0.42	$0.86	$0.20	$0.01	$1.49
2003	$0.50	$1.05	$0.24	$0.15	$1.94
2004	$0.51	$0.93	$0.26	$0.13	$1.83
2005	$0.80	$0.72	$0.26	$0.11	$1.89
2006	$0.53	$0.74	$0.29	$0.08	$1.64
2007	$0.63	$0.72	$0.29	$0.06	$1.70
2008	$0.70	$0.38	$0.34	$0.08	$1.50
2009	$0.34	$0.29	$0.36	$0.05	$1.04
2010	$0.36	$0.35	$0.45	$0.07	$1.23
2011	$0.32	$0.36	$0.41	$0.09	$1.18
2012	$0.26	$0.41	$0.46	$0.04	$1.17
2013	$0.25	$0.41	$0.76	$0.04	$1.46
2014	$0.33	$0.42	$0.40	$0.12	$1.27
2015	$0.23	$0.42	$0.37	$0.11	$1.13
2016	$0.11	$0.41	$0.38	$0.05	$0.95
2017	$0.14	$0.47	$0.42	$0.06	$1.09
2018	$0.18	$0.46	$0.40	$0.06	$1.10
2019	$0.12	$0.46	$0.43	$0.04	$1.05
2020	$0.10	$0.46	$0.47	$0.03	$1.06
2021	$0.19	$0.49	$0.48	$0.08	$1.24

12 See 157 FERC ¶ 61,122 (2016).
13 See 164 FERC ¶ 61,224 (2018).
14 OATT Attachment O § 4.7.2 (Primary Frequency Response).

15 The total prices in this table are a load-weighted, average system price per MWh by category, even if each category is not charged on that basis. These totals are presented for informational purposes and should not be used to calculate the costs of any specific market activity in PJM.
16 Note: The totals in Table 10-4 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.
17 Reactive totals include FERC approved rates for reactive capability.

Market Procurement of Real Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary reserves and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be weighed against the benefit the ancillary service provides. The degree to which PJM markets account for these interactions depends on the timing of the product clearing and software limitations and the accuracy of unit parameters and offers.

The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services. Resources categorized as flexible tier 2 reserve, those that can provide reserves by backing down according to their ramp rate, are jointly cleared along with energy in every real-time market solution. Given the joint clearing of energy and flexible tier 2, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible tier 2. PJM should never need to pay uplift to flexible tier 2. The uplift paid to flexible tier 2 results from issues with the dispatch and pricing software timing. Inflexible tier 2 reserves, provided by resources that require longer notice to take actions to prepare for reserve deployment, are not cleared along with energy in the real-time market solution. Inflexible tier 2 reserves are cleared hourly by the Ancillary Service Optimizer (ASO). The ASO uses forward looking information about the energy market, flexible tier 2, tier 1, and regulation to estimate the costs and benefits of using a resource for inflexible tier 2 synchronized reserves.

Nonsynchronized reserves are cleared with every real-time energy market solution, but their costs are not fully known by the real-time energy market software (RT SCED) because the resources are offline. PJM uses an estimate of the cost of using a resource for nonsynchronized reserve instead of energy from a previously solved IT SCED solution. IT SCED runs every 15 minutes looking ahead at target dispatch times up to two hours in the future. The energy commitment decisions for the offline resources have already been made when the RT SCED clears the nonsynchronized reserve market. RT SCED compares the IT SCED estimated cost of nonsynchronized reserve clearing to the RT SCED determined cost of synchronized reserve clearing in satisfying the primary reserve requirement. Nonsynchronized reserve clearing indirectly interacts with energy clearing through both products' substitutability with synchronized reserves.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which is uses the RT SCED solution as an input. The RT SCED is partially, but not fully clearing the reserve market. The software determining the prices is not clearing the regulation market. With fast start pricing implementation on September 1, 2021, the pricing calculations in LPC are not the same prices that result from the market clearing in RT SCED.

Recommendations

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.[18])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run

18 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[19] FERC rejected.[20])

- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[21])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.[22])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[23])
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources be paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed because performance is only measured for events 10 minutes or longer. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use

19 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
20 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
21 *Id.*
22 *Id.*
23 *Id.*

DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)

- The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that, in order to mitigate market power, offers in the DASR market be based on opportunity cost only. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The black start units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Adopted 2021.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.[24] Status: Partially adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[25] (Priority: Medium. First reported 2020. Status: Not adopted.)

Conclusion

The design of the PJM Regulation Market is significantly flawed.[26] The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF

24 The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.
25 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, <https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities>.
26 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

in settlement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017.[27] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[28] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[29]

The structure of the tier 2 synchronized reserve market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market clearing prices and with offers based on the marginal cost of producing the product plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, the $7.50 margin is not a cost. The margin is effectively a rule-based form of economic withholding and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. The variable operating and maintenance component of the synchronized reserve offer should also be eliminated. All variable operating and maintenance costs are incurred to provide energy and to make units available to provide energy. There are no variable operating and maintenance costs associated with providing synchronized reserve. Reserve market design changes approved by FERC and scheduled for implementation in October 2022 will eliminate the $7.50 per MW margin and the variable operations and maintenance costs.[30]

Participant performance has not been adequate for tier 2 synchronized reserve. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. Actual participant performance means that the penalty structure is not an adequate incentive for performance. The October 2022 reserve market design changes do not respond to the MMU's recommendations to increase the penalties for nonperformance. All synchronized reserves should also have the same obligation to perform, but the proposed changes will mean that not all cleared reserves will be called on to perform during synchronized reserve events.[31]

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Tier 1 resources have no obligation to perform and pay no penalties if they do not perform, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are already paid for their response if they do respond to a synchronized reserve event. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule has added more than $100 million to the cost of primary reserve since 2014. The reserve market design changes approved by FERC and scheduled for implementation in 2022 will consolidate Tier 1 and Tier 2 reserves into a single synchronized reserve product, with a stronger must offer requirement and a single clearing price.[32] This will eliminate the payment of Tier 1 based on the nonzero nonsynchronized reserve price.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there

27 18 CFR § 385.211.
28 162 FERC ¶ 61,295 (2018).
29 170 FERC ¶ 61,259 (2020).
30 See FERC Docket No. EL19-58.
31 See PJM, "Intelligent Reserve Deployment – PJM Package (SRDTF)," Presentation to the Members Committee (January 26, 2022), <https://pjm.com/-/media/committees-groups/committees/mc/2022/20220126/20220126-cac-1-synchronous-reserve-deployment-presentation.ashx>.
32 See FERC Docket No. EL19-58.

can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the regulation market results were not competitive, and the market design is significantly flawed. The MMU concludes that the synchronized reserve market results were competitive, although the $7.50 margin should be removed. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Primary Reserve

NERC Performance Standard BAL-002-3, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, requires PJM to carry sufficient contingency reserve to recover from a sudden balancing contingency (usually a loss of generation). The Contingency Event Recovery Period is the time required to return the ACE to zero if it was zero or positive before the event or to its pre-event level if it was negative at the start of the event. NERC standards set the Contingency Event Recovery Period as 15 minutes and Contingency Reserve Restoration Period as 90 minutes.[33] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[34] PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. PJM does not have a Contingency Reserve Restoration Period standard.

Market Structure

Demand

PJM requires that 150 percent of the largest single contingency on the system be maintained as primary reserve plus 190 MW. PJM can make temporary adjustments to the primary reserve requirement when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

The primary reserve market requirement is set equal to 150 percent of the largest single contingency for each market solution, ASO, IT SCED, and RT SCED. This is usually the output of the largest generating unit to which PJM adds 190 MW. In cases where temporary switching conditions create the risk that a single fault could remove several generators, PJM will define the largest single contingency as the sum of the output of those generators.[35]

PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.[36] Such additional reserves are committed as part of the hourly (ASO) and five minute (RT SCED) processes. In 2021, the average primary reserve requirement for the RTO Zone was 2,449.6 MW. The average primary reserve requirement in the MAD Subzone was 2,436.4 MW. These averages include the hours when PJM raised the requirements.

The MMU identified instances when PJM increased the primary and synchronized reserve requirements (Table 10-5). On November 1, 2021, PJM doubled the reserve requirements for 40 hours, which resulted in significantly higher prices and reserve levels for all real-time reserve products.

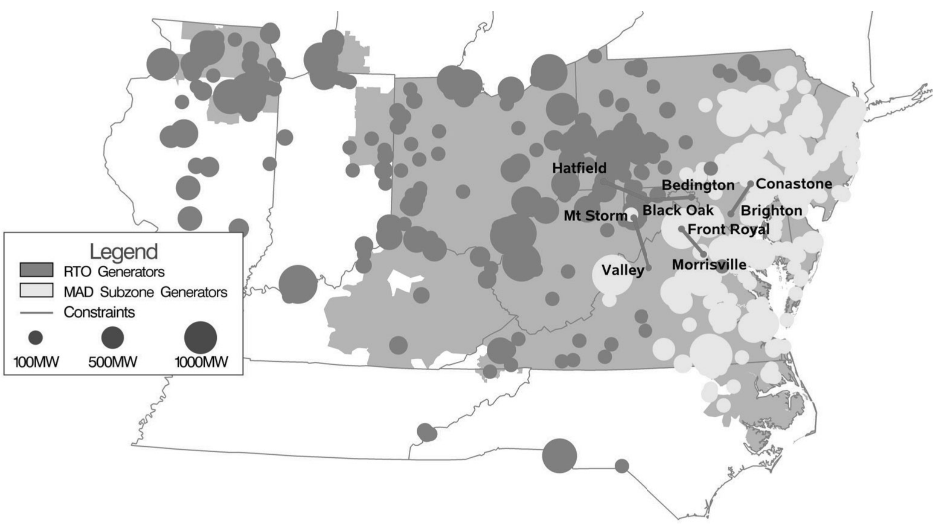
33 See PJM "Manual 12: Balancing Operations," Rev. 43 (June 6, 2021) Attachment D, "the Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes."
34 See PJM "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 40 (Dec. 15, 2021).
35 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 117 (Nov. 1, 2021)
36 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 117 (Nov 1, 2021), p. 84

Table 10-5 Temporary adjustments to primary and synchronized reserve: 2021

From	To	Number of Hours	Amount of Adjustment
6-Mar-21	8-Mar-21	34	Primary Reserve (255 MW), Synchronized Reserve (170 MW)
15-Mar-21	29-Mar-21	230	Primary Reserve (230 MW), Synchronized Reserve (160 MW)
14-Jun-21	17-Jun-21	64	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
28-Aug-21	30-Aug-21	50	Primary Reserve (60MW), Synchronized Reserve (125 MW)
30-Aug-21	18-Oct-21	0	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
18-Oct-21	18-Oct-21	18	Primary Reserve (210 MW), Synchronized Reserve (140 MW)
22-Oct-21	30-Oct-21	174	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
1-Nov-21	2-Nov-21	40	Primary Reserve (1,780 MW), Synchronized Reserve (1,180 MW)

Transmission constraints can limit the deliverability of reserves within the RTO, requiring the definition of a subzone. PJM defines a single subzone, the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[37] Figure 10-1 is a map of constraints and major generation sources. The constraints separating the RTO Zone and MAD Subzone are defined by underlying grid topology. The RTO Zone into MAD Subzone constraints reflect limits on the transmission line capacity that separate the RTO Zone and MAD Subzone. If, in the case of a spinning event, the current economic dispatch plus the current synchronized market dispatch would overload the constraint, then all additional synchronized reserve MW must be cleared from the unconstrained side of the constraints. When this occurs, the synchronized reserve prices between the RTO Zone and the MAD Subzone will diverge. PJM operators are authorized to define additional separate subzones under certain conditions.[38] In practice, PJM has always maintained only the MAD Subzone but for any market solution several distinct constraining paths are analyzed and the most limiting one becomes the definition for that solution.

Figure 10-1 PJM RTO Zone and MAD Subzone map of constraints and generation sources



37 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 117 (Nov. 1, 2021).
38 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 117 (Nov. 1, 2021), p. 86.

The most limiting transmission constraint for power flow from the RTO Zone into the MAD Subzone since August 2017, has been the AP South Interface. The most frequent constraint in 2021 is Brighton-Conastone, then Bedington-Black Oak, and Cloverdale-Lexington.

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the most severe single contingency (MSSC) plus 190 MW.[39] PJM requires primary reserves in the amount of 150 percent of the largest single contingency with at least 100 percent of the requirement made up of synchronized reserves.[40] In 2021, the average synchronized reserve requirement was 1,687.6 MW in the MAD Subzone and 1,696.4 MW in the RTO Zone. The synchronized reserve requirement is calculated for every real-time market dispatch solution.

Supply

The demand for primary reserve is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and nonsynchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. After the synchronized reserve requirement is satisfied, the remainder of primary reserves is from the least expensive combination of synchronized and nonsynchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement as well as PJM's synchronized reserve requirement. In the MAD Subzone, an average of 841.9 MW of tier 1 was identified by the dispatch solutions as available in 2021 (Table 10-6).[41] Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement or reduced the need for tier 2 synchronized reserve to self scheduled reserves in 8.1 percent of dispatch solutions in 2021. In the RTO Zone, an average of 1,565.7 MW of tier 1 was available (Table 10-7) fully satisfying the synchronized reserve requirement in 44.4 percent of real-time dispatch solutions.

Regardless of online/offline state, all nonemergency generation capacity resources must submit a daily offer for tier 2 synchronized reserve in Markets Gateway prior to the offer submission deadline (14:15 the day prior to the operating day). Resources listed as available for tier 2 synchronized reserve without a synchronized reserve offer will have their offer price automatically set to $0.00. Offer MW and other non-cost offer parameters can be changed during the operating day. Owners who opt in for intraday updates may change their offer price up to 65 minutes before the hour. Certain unit types including nuclear, wind, solar, and energy storage resources, a re expected to have zero MW tier 2 synchronized reserve offer quantities.[42]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2.

In 2021, in the MAD Subzone, there was an average of 1,255.5 MW of eligible nonsynchronized reserve supply available to meet the average demand for primary reserve. (Table 10-7) In the RTO Zone, an average of 2,742.7 MW of supply was available to meet the average demand of 1,607.5 MW (Table 10-7).

Table 10-6 provides the average dispatch solution reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from January 2020 through December 2021.

39 NERC BAL-002-3. "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," September 25, 2018. <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.

40 "PJM Manual 13: Emergency Operations," Rev 82 (Jan. 1, 2022), p. 18.

41 ASO, Ancillary Services Optimizer. This is the hour-ahead market software that optimizes ancillary services with energy. ASO schedules hourly the Tier 2 Synchronized Reserve, Regulation, and Nonsynchronized Reserves.

42 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 117 (Nov. 1, 2021).

Table 10-6 Average reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2020 through December 2021

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2020	Jan	1,276.6	325.9	1,249.0	2,851.5
2020	Feb	1,026.9	193.6	1,219.6	2,440.1
2020	Mar	980.7	259.0	1,231.8	2,471.4
2020	Apr	1,150.5	199.9	1,067.7	2,418.1
2020	May	911.1	200.5	1,177.5	2,289.0
2020	Jun	1,276.2	142.5	976.6	2,395.4
2020	Jul	995.4	210.5	1,216.0	2,421.9
2020	Aug	881.4	148.3	1,200.6	2,230.3
2020	Sep	1,016.9	88.5	1,123.2	2,228.6
2020	Oct	724.1	290.2	1,247.8	2,262.2
2020	Nov	566.4	257.2	1,188.8	2,012.5
2020	Dec	689.0	252.2	1,319.6	2,260.8
2020	Average	957.9	214.0	1,184.8	2,356.8
2021	Jan	835.6	251.1	1,330.6	2,417.3
2021	Feb	974.9	215.1	1,242.7	2,432.7
2021	Mar	881.9	213.2	1,162.6	2,257.7
2021	Apr	689.7	315.5	1,274.8	2,280.0
2021	May	651.4	247.5	1,141.4	2,040.2
2021	Jun	836.5	202.5	1,264.3	2,303.3
2021	Jul	891.3	206.0	1,262.9	2,360.2
2021	Aug	912.2	221.1	1,269.3	2,402.6
2021	Sep	909.2	234.1	1,207.5	2,350.8
2021	Oct	595.8	433.5	1,211.3	2,240.5
2021	Nov	573.7	409.7	1,326.8	2,310.2
2021	Dec	741.6	340.1	1,337.7	2,419.5
2021	Average	791.2	274.1	1,252.7	2,317.9

Table 10-7 shows the average dispatch solution reserves, by type of reserve, satisfying the primary reserve requirement in the RTO Zone in January 2020 through December 2021.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2020 through December 2021

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2020	Jan	2,416.4	486.8	1,364.8	4,268.0
2020	Feb	2,284.2	283.3	1,279.6	3,847.1
2020	Mar	2,155.1	458.7	1,365.6	3,979.4
2020	Apr	2,228.6	342.1	1,174.0	3,744.7
2020	May	2,128.3	297.4	1,250.6	3,676.3
2020	Jun	2,728.9	283.7	1,082.7	4,095.3
2020	Jul	2,109.4	402.2	1,363.5	3,875.1
2020	Aug	1,972.1	398.8	1,387.0	3,757.9
2020	Sep	2,053.8	299.4	1,271.0	3,624.1
2020	Oct	1,381.3	778.2	1,612.3	3,771.7
2020	Nov	1,499.7	683.9	1,509.5	3,693.1
2020	Dec	1,512.4	697.0	1,648.3	3,857.7
2020	Average	2,039.2	450.9	1,359.1	3,849.2
2021	Jan	1,761.2	506.7	1,512.5	3,780.4
2021	Feb	1,848.8	600.3	1,515.2	3,964.3
2021	Mar	1,705.5	593.1	1,454.1	3,752.7
2021	Apr	1,313.5	748.3	1,589.6	3,651.2
2021	May	1,371.4	790.1	1,569.2	3,731.2
2021	Jun	1,701.2	614.9	1,575.7	3,891.8
2021	Jul	1,674.4	663.9	1,588.6	3,926.9
2021	Aug	1,768.0	709.8	1,598.6	4,076.4
2021	Sep	1,781.2	654.1	1,493.8	3,929.1
2021	Oct	1,111.4	816.3	1,693.7	3,871.2
2021	Nov	1,169.1	796.1	1,798.7	3,991.9
2021	Dec	1,619.2	535.1	1,563.4	3,825.8
2021	Average	1,568.7	669.1	1,579.4	3,866.1

Supply and Demand

The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED); and the real-time (short term) security constrained economic dispatch market solution (RT SCED).

All dispatch solutions determine the actual primary reserves required as 150 percent of the largest contingency plus 190 MW. Of this, synchronized reserves must be 100 percent of the largest contingency plus 190 MW.

If the tier 1 synchronized reserve plus ASO committed inflexible tier 2 synchronized reserve does not meet the requirement, RT SCED will commit available flexible tier 2 synchronized reserve. If there is an excess of synchronized reserve, the RT SCED may decommit previously committed flexible synchronized reserve.

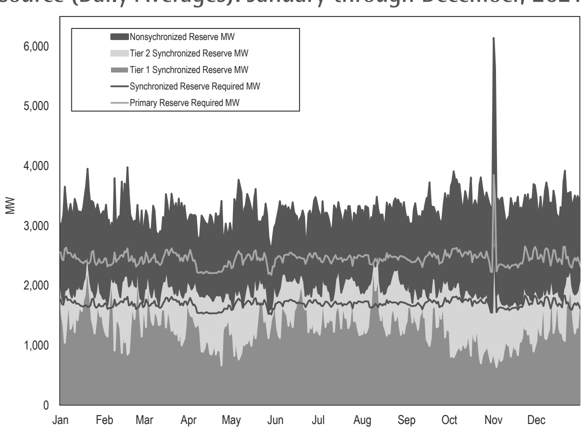
The ASO satisfied the primary reserve requirement for the RTO Zone and the MAD Subzone in all hours of

2021. RT SCED for the MAD Subzone was short, failing to satisfy the synchronized reserve requirement in 24 intervals. Three of the dispatch solutions, occurred during temporary increases in the required synchronized reserve and nonsynchronized reserve on March 17 and March 22. Three of the short intervals occurred during the 12 minute spinning event of November 12, 2021.

The market solution first estimates how much tier 1 synchronized reserve is available. If there is enough tier 1 MW available to satisfy the synchronized reserve requirement, then RT SCED economically assigns available synchronized reserve and nonsynchronized reserve to meet the remaining primary reserve requirement. If there is not enough tier 1 synchronized reserve then the remaining synchronized reserve requirement is filled with tier 2 synchronized reserve. After synchronized reserve is assigned, the primary reserve requirement is filled by economically assigning synchronized reserve and nonsynchronized reserve.

Figure 10-2 shows how the daily average market solutions satisfy the primary reserve requirement for the RTO Zone.

Figure 10-2 RTO reserve zone primary reserve MW by source (Daily Averages): January through December, 2021



In 2021, tier 1 and tier 2 were both essential to satisfying the synchronized reserve requirement. Tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirement in both the RTO Zone and the MAD Subzone.

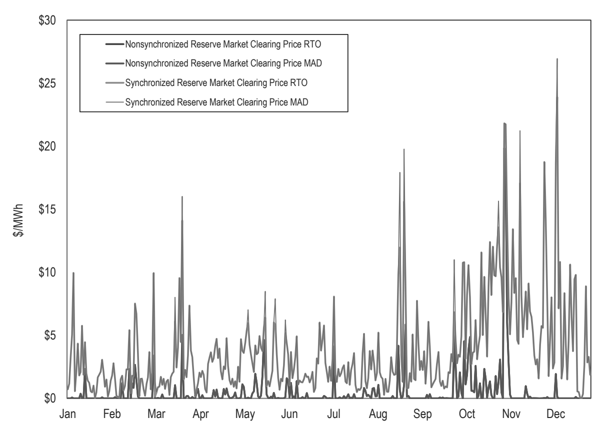
Price and Cost

The price of primary reserves results from the demand curve for primary reserves and the supply of primary reserves. The demand curve is modeled in each of the primary reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for primary reserves has two steps, with an $850 penalty factor for primary reserve levels ranging from 0 MW to a MW amount equal to 150 percent of the MSSC and a constraint with a $300 penalty factor for primary reserves ranging from 150 percent of MSSC to 150 percent of MSSC plus 190 MW.

The supply of primary reserves is made up of available tier 1 and tier 2 synchronized reserves and nonsynchronized reserves. Offer prices for synchronized reserve are capped at $7.50 plus costs plus marginal cost.

Figure 10-3 shows daily weighted average synchronized and nonsynchronized market clearing prices in 2021. The MAD SRMCP and RTO SRMCP price diverged in 45 five minute intervals in 2021.

Figure 10-3 Daily average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: 2021



Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event. The tier 1 synchronized reserve for a unit is estimated as the lesser of the available 10 minute ramp or the difference between the economic dispatch point and the synchronized reserve maximum output. By default the synchronized reserve maximum for a resource is equal to its economic maximum. Resource owners may request a lower synchronized reserve maximum if a physical limitation exists.[43] Tier 1 resources are identified by the market solution. Tier 1 synchronized reserve has an incremental cost of zero. Tier 1 synchronized reserve is paid under two circumstances. Tier 1 reserves are paid when they respond to a synchronized reserve event. Tier 1 reserves are paid the synchronized reserve market clearing price when the nonsynchronized reserve market clearing price is above $0.

While PJM relies on tier 1 resources to respond to a synchronized reserve event, tier 1 resources are not obligated to respond during an event. Tier 1 resources are credited if they do respond but are not penalized if they do not.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve are available for tier 1 synchronized reserve and any response to a spinning event will be credited at the Synchronized Energy Premium Price.

Beginning in 2014, DGP (Degree of Generator Performance) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution. The available tier 1 MW estimated by the market solution for each resource is based upon its economic dispatch, and submitted synchronized reserve ramp rate, adjusted by its DGP. PJM communicates to generation operators whose tier 1 MW is part of the market solution the latest estimate of units' tier 1 MW and units' current DGP.[44] DGP should be documented in PJM's market rules.[45] DGP violates the basic PJM principle that generation owners are solely responsible for their own offers. In addition, DGP is a crude estimate of ramp rates and does not account for the actual discontinuities along unit offer curves. PJM will remove DGP with implementation of the reserve market changes in October 2022.

The supply of tier 1 synchronized reserve available to the market solution is adjusted by eliminating tier 1 MW from unit types that cannot reliably provide synchronized reserve. These unit types are nuclear, wind, solar, landfill gas, energy storage, and hydro units.[46] These unit types are credited the synchronized energy premium price, like any other responding unit, if they respond to a spinning event. These units will not, however, be paid as tier 1 resources when the nonsynchronized reserve market clearing price goes above $0. There is a review process for resources excluded by default from the tier 1 estimate that request to be included.[47] PJM also excludes units, regardless of type, that it deems unreliable as tier 1, though it allows those resources to provide tier 2 synchronized reserve.

Table 10-8 provides tier 1 synchronized reserve supplied by resource and fuel type in 2021, including all tier 1 credited for responding to synchronized reserve events and paid when the nonsynchronized reserve price exceeded $0 per MW.

Table 10-8 Supply of tier 1 synchronized reserve by resource and fuel type: 2021

Unit/Fuel Type	Percent by MW	Percent by Credits
Combined Cycle	42.7%	46.8%
Steam - Coal	22.6%	22.1%
Hydro - Run of River	10.8%	8.9%
CT - Natural Gas	7.9%	8.0%
Wind	5.0%	4.3%
Solar	4.8%	4.8%
Steam - Natural Gas	2.7%	2.8%
Hydro - Pumped Storage	1.7%	0.9%
RICE - Natural Gas	0.8%	0.7%
Steam - Other	0.7%	0.7%
DSR	0.2%	0.1%
Nuclear	0.1%	0.0%
CT - Oil	0.0%	0.0%
RICE - Other	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Fuel Cell	0.0%	0.0%
RICE - Oil	0.0%	0.0%

43 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 117 (Nov. 1, 2021).

44 PJM. Ancillary Services, "Communication of Synchronized Reserve Quantities to Resource Owners," (May 6, 2015). <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx>

45 See PJM, Generation Performance Monitor and Degree of Generator Performance Whitepaper. <http://www.pjm.com/-/media/etools/oasis/system-information/generation-performance-monitor-and-degree-of-generator-performance-white-paper.ashx>.

46 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 117 (Nov. 1, 2021).

47 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 117 (Nov. 1, 2021).

In 2021, the SCED market solutions estimated that tier 1 MW from an average of 62 units could have an average of 1,563.7 MW of ramp available in a spinning event. For the 18 spinning events in 2021, PJM paid a total of 5,004.3 MW of tier 1 response across 46 intervals. Settlements include units like wind, solar, nuclear, and demand response which are not a part of the estimated tier 1 in the SCED market solutions.

By observing spin event response recorded in PJM's SCADA data, the MMU estimates actual response as the sum of the products contributing to total ACE increase from the time the event is initiated to 10 minutes after the event is initiated. Total increase in ACE is a summation not only of tier 1 response, but also of tier 2 response, regulation A and regulation D actual response (RegD response is sometimes a MW increase and sometimes a MW decrease), and changes to net imports/exports across PJM's boundaries (sometimes an increase and sometimes a decrease in MW).

In the RTO Reserve Zone, the average estimated tier 1 synchronized reserve was 1,563.7 MW (Table 10-7). In 36.8 percent of dispatch solutions, the estimated tier 1 synchronized reserve was greater than the synchronized reserve requirement, meaning that the synchronized reserve requirement was met entirely by tier 1 synchronized reserve plus self-scheduled tier 2.

In 2021, the average estimated tier 1 synchronized reserve within the MAD Subzone was 788.2 MW (Table 10-6). In 4.3 percent of dispatch solutions the estimated tier 1 synchronized reserve available within the MAD Subzone plus the self-scheduled tier 2 in MAD was greater than the synchronized reserve requirement and no tier 2 market needed to be cleared.

Demand

There is no required amount of tier 1 synchronized reserve. The estimated tier 1 MW are used to satisfy the total required amounts of synchronized and primary reserve.

The ancillary services market solution treats the cost of estimated tier 1 synchronized reserve as $0, even when the nonsynchronized reserve market clearing price is above $0. As a result, the optimization cannot and does not minimize the total cost of primary reserves. The MMU recommends that tier 1 synchronized reserve not be paid when the nonsynchronized reserve market clearing price is above $0.

Supply and Demand

The price of synchronized reserves results from the demand curve for synchronized reserves and the supply of synchronized reserves. The demand curve is modeled in each of the synchronized reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for synchronized reserves has two steps, with an $850 penalty factor for synchronized reserve levels ranging from 0 MW to a MW amount equal to 100 percent of the MSSC and a constraint with a $300 penalty factor for synchronized reserves ranging from 100 percent of MSSC to 100 percent of MSSC plus 190 MW.

When solving for the synchronized reserve requirement the market solution first estimates the amount of tier 1 available from the energy dispatch. If the requirement is not filled by tier 1, it then commits tier 2 beginning with all self scheduled synchronized reserve.

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone (green area of Figure 10-2). If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve.

Tier 1 Synchronized Reserve Payments

Tier 1 synchronized reserve is awarded credits under two distinct circumstances. In response to a spinning event, all resources (except scheduled tier 2 resources) are paid for increasing output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[48] This is the Synchronized Energy Premium Price. Spinning event response is calculated as the highest output between 9 minutes and 11 minutes after the event is declared minus the lowest output between one minute before and one minute after the event is declared. Generator outputs are measured and reported to PJM every four seconds via SCADA. Total response credited to a resource is capped at 110 percent of estimated

48 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 117 (Nov. 1, 2021).

capability. These rules apply to all resources that are not scheduled tier 2 resources. As a result, spinning event response involves more MW response than the original estimate of tier 1. Many resources that are not included in PJM's estimate of tier 1 nevertheless respond to spinning events and in accordance with the PJM Tariff are paid the Synchronized Energy Premium Price. This can include incidental response from nuclear units or steam turbines running at maximum output. Such response is expected when the response is measured as the highest output for the two minute period around the end of an event minus lowest output from the two minute period around the start of an event. Tier 1 synchronized reserve that is part of the estimate (at market solution time) when there is no spinning event is also credited for its full estimated MW whenever the nonsynchronized reserve market clearing price is above $0.

In the event that the nonsynchronized reserve market clearing price is above $0 and there is a spinning event, estimated tier 1 is credited with the lesser of its actual response or its estimated capability times the SRMCP. Tier 1 synchronized reserve not part of the estimate is credited the SRMCP times its actual response.[49] In 2021, the nonsynchronized reserve market clearing price was above $0 in 2.9 percent of intervals.

In 2021, tier 1 synchronized reserve spinning event response credits of $375,832 were paid for 18 spinning events averaging 8.9 minutes. Table 10-9 shows the number of spinning events each month, the credits paid for tier 1 response, the number of MWh credited, and the actual response in MW.

49 See PJM "Manual 28: Operating Agreement Accounting," Rev. 85 (Sep. 1, 2021) p. 59.

Table 10-9 Tier 1 synchronized reserve event response credits: January 2020 through December 2021

Year	Month	Number of Spinning Events	Total Tier 1 Spinning Event Credits	Total Tier 1 Spinning Event Credited (MWh)	Total Tier 1 Spinning Response from Event Start to Event End (MW)
2020	Jan	2	$22,200	453.2	5,438.8
2020	Feb	4	$56,595	1,148.2	13,778.8
2020	Mar	1	$3,514	70.3	843.5
2020	Apr	1	$5,873	118.2	1,418.5
2020	May	1	$11,302	226.0	2,712.6
2020	Jun	0	NA	NA	NA
2020	Jul	3	$3,429	699.8	8,397.2
2020	Aug	0	NA	NA	NA
2020	Sep	1	$11,390	236.2	2,843.1
2020	Oct	2	$23,038	460.8	5,713.0
2020	Nov	1	$7,964	159.3	2,019.3
2020	Dec	1	$10,050	201.0	2,462.1
2020	Total	17	$186,176	3,773.0	45,590.9
2021	Jan	1	$6,796	135.9	1,165.0
2021	Feb	0	NA	NA	NA
2021	Mar	1	$15,729	314.6	1,715.8
2021	Apr	2	$40,442	808.8	4,677.8
2021	May	1	$21,822	436.4	2,618.6
2021	Jun	2	$16,275	325.5	3,183.2
2021	Jul	2	$16,026	320.5	2,999.1
2021	Aug	2	$46,487	929.7	4,666.3
2021	Sep	1	$126,863	279.2	2,094.2
2021	Oct	2	$27,267	545.3	3,800.4
2021	Nov	3	$50,939	1,018.8	6,024.5
2021	Dec	1	$7,188	143.8	1,232.3
2021	Total	18	$375,832	5,258.6	34,177.2

Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve has zero marginal cost and the corresponding competitive price for tier 1 synchronized reserves is also zero. However, the PJM rules artificially create a marginal cost of tier 1 when the price of nonsynchronized reserve is greater than zero and tier 1 is paid the tier 2 price. The PJM market solutions do not include that marginal cost and therefore do not solve for the efficient level of tier 1, tier 2 and nonsynchronized reserve in those cases. When called to respond to a spinning event, tier 1 is compensated at the Synchronized Energy Premium Price (Table 10-12). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the nonsynchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves (Table 10-10). In 2021, the nonsynchronized reserve market clearing price was above $0.00 in 2.9 percent of all intervals. For those intervals, tier 1 synchronized reserve was paid $7,364,936 for an average of 639.3 MW per interval of which $7,354,224 was for intervals outside of spinning events.

Table 10-10 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 2020 through December 2021

Year	Month	Number of Intervals When NSRMCP > $0	Weighted Average SRMCP When NSRMCP > $0	Total Tier 1 MWh When NSRMCP > $0	Total Tier 1 Credits When NSRMCP > $0	Average Tier 1 MWh Monthly When NSRMCP > $0
2020	Jan	0	NA	NA	NA	NA
2020	Feb	0	NA	NA	NA	NA
2020	Mar	0	NA	NA	NA	NA
2020	Apr	27	$6.17	3,654.9	$22,372.4	456.9
2020	May	23	$12.22	3,005.4	$19,219.4	333.9
2020	Jun	116	$8.87	17,163.0	$130,139.5	490.4
2020	Jul	166	$13.31	22,696.6	$253,682.3	687.8
2020	Aug	309	$18.16	42,499.8	$531,927.9	708.3
2020	Sep	50	$4.50	7,277.5	$28,657.9	519.8
2020	Oct	944	$15.46	148,481.8	$1,760,874.3	1,124.9
2020	Nov	255	$20.20	33,087.6	$448,263.5	675.3
2020	Dec	124	$8.94	15,314.0	$125,588.3	528.1
2020	Total	2,014	$12.36	293,180.6	$3,320,725.6	613.9
2021	Jan	31	$36.20	3,625.7	$75,336.8	604.3
2021	Feb	160	$20.31	19,953.0	$326,371.9	739.0
2021	Mar	60	$95.30	7,775.0	$724,172.5	518.3
2021	Apr	196	$10.34	24,978.1	$203,281.3	531.4
2021	May	644	$12.75	74,895.9	$797,735.9	720.2
2021	Jun	199	$12.62	25,628.0	$255,053.0	596.0
2021	Jul	95	$27.79	13,751.7	$325,970.0	528.9
2021	Aug	123	$56.79	15,098.7	$758,394.8	503.3
2021	Sep	123	$26.95	18,665.3	$454,767.7	777.7
2021	Oct	865	$20.82	113,069.8	$1,828,569.7	796.3
2021	Nov	490	$33.16	54,585.5	$1,527,555.0	941.1
2021	Dec	22	$69.35	2,487.4	$87,728.0	414.6
2021	Total	3,008	$35.20	374,514.1	$7,364,936.6	639.3

The additional payments to tier 1 synchronized reserves under the shortage pricing rule are a windfall. Table 10-11 shows the amount of windfall paid to tier 1 resources from 2014 through 2021.

Table 10-11 Windfall payments made to tier 1 resources: 2014 through 2021

Year	Windfall Payment
2014	$89,719,045
2015	$34,397,441
2016	$4,948,084
2017	$2,197,514
2018	$4,732,025
2019	$3,217,178
2020	$3,320,726
2021	$7,354,224

The additional payment does not create an incentive to provide more tier 1 synchronized reserves. The additional payment is not a payment for performance; all estimated tier 1 receives the higher payment regardless of whether they provide any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In 2021, there were five spinning events of 10 minutes or longer. In those events, an average of 55.0 percent of the estimated tier 1 responded and 63.2 percent of tier 2 responded.

The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately.[50] Tier 1 should be compensated only for a response to synchronized reserve events, as it was before the shortage pricing changes. This compensation requires that when a synchronized reserve event is called, all tier 1 response is paid the synchronized energy premium price.

50 This recommendation was presented as a proposal, "Tier 1 Compensation," to the Markets and Reliability Committee Meeting, October 22, 2015. The MMU proposal and a PJM counterproposal were both rejected.

PJM's current tier 1 compensation rules are presented in Table 10-12.

Table 10-12 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Interval as Currently Implemented by PJM		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(estimated tier 1 MW, actual response MWi)

The MMU's recommended compensation rules for tier 1 MW are in Table 10-13.

Table 10-13 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Recommended by MMU		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi

Tier 2 Synchronized Reserve Market

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves. When the synchronized reserve requirement cannot be met by tier 1 synchronized reserve, PJM clears a market to satisfy the requirement with tier 2 synchronized reserve. Tier 2 synchronized reserve is provided by online resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch point. Tier 2 synchronized reserve is also provided by demand resources that have offered to reduce load in the event of an synchronized reserve event. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event. Tier 2 resources have a must offer requirement. Some tier 2 resources are scheduled by the ASO 60 minutes before the operating hour and are committed to provide synchronized reserve for the entire hour. Tier 2 resources are paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC). Demand response resources are paid the clearing price (SRMCP).

Synchronized reserve resources can be flexible or inflexible. Inflexible resources are defined as those resources that require an hourly commitment due to minimum run times or staffing constraints. Examples of inflexible reserves are synchronous condensers operating in condensing mode, resources with an economic minimum (EcoMin) equal to economic maximum (EcoMax), offline CTs and hydro that can operate in the condense mode, and demand resources. Inflexible tier 2 synchronized reserve resources are committed for a full hour by the hour ahead ASO market solution. Inflexible resources require a 30 minute notification time and cannot be released for energy during the operating hour. The inflexible commitments made by the hour ahead ASO solution may satisfy only part of the tier 2 requirement. The actual requirement is determined by the RT SCED solution and the requirement not satisfied by inflexible units is satisfied by flexible units. Flexible resources are already online for energy, require no notification time, and can be automatically dispatched.

During the operating hour, RT SCED can dispatch additional tier 2 resources. RT SCED can redispatch online tier 1 generating resources as tier 2 synchronized reserve to meet the synchronized and primary reserve requirements within the operational hour. Resources that are redispatched as tier 2 within the hour are paid the SRMCP plus any lost opportunity costs that exceed the SRMCP.

Market Structure

Supply

PJM has a must offer tier 2 synchronized reserve requirement. All nonemergency generating resources are required to submit tier 2 synchronized reserve offers. All online, nonemergency generating resources are deemed available to provide both tier 1 and tier 2 synchronized reserve although certain unit types are exempt. If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all offline emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[51]

In 2021, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 4,606.5 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 36,342.6 MW of tier 2 synchronized reserve offers (Figure 10-6).

The supply of tier 2 synchronized reserve offered in 2021 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in 2021 was from CTs running natural gas (Table 10-14) followed by demand resources. Although demand resources are limited to providing no more than 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. This means that in some hours demand resources make up considerably more than 33 percent of the cleared tier 2 MW. Demand resources often offer at a price of $0, do not incur an LOC, and clear even when the price is $0. As a result, their share of credits in the synchronized reserve market is much less than their share of cleared MW.

Table 10-14 Supply of Tier 2 Synchronized Reserve by Resource Type and Fuel Type: 2021

Unit / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	35.9%	43.2%
DSR	28.4%	11.7%
CT - Oil	12.5%	12.8%
Combined Cycle	11.9%	24.8%
Hydro - Run of River	8.0%	3.9%
Steam - Coal	2.2%	2.3%
Hydro - Pumped Storage	0.5%	0.4%
RICE - Natural Gas	0.4%	0.6%
Steam - Natural Gas	0.1%	0.2%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
RICE - Other	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Steam - Other	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Demand

On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the most severe single contingency (MSSC) as the first step, and extended by a 190 MW second step.[52] There are two circumstances in which PJM may alter the base portion of the synchronized reserve requirement from its 100 percent of the largest contingency value. Reserve requirements may be increased during a temporary switching condition when transmission outages or configuration problems cause several generation resources to be subject to a single contingency. When PJM operators anticipate periods of high load, they may bring on additional units to account for increased operational uncertainty in meeting load. When a Hot Weather Alert, Cold Weather Alert or an emergency procedure (as defined in Manual 11 § 4.2.2 Synchronized Reserve Requirement Determination) has been issued for the operating day, operators may increase the synchronized reserve requirement up to the full amount of the additional MW brought on line.[53]

In 2021, the average synchronized reserve requirement was 1,697.1 MW in the RTO Zone and 1,696.5 in the MAD Subzone. These averages include temporary increases to the synchronized reserve requirement.

51 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 117 (Nov. 1, 2021).

52 See the *2021 Quarterly State of the Market Report: January through September*, Section 3: Energy Market, at "Operating Reserve Demand Curves".

53 PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 117 (Nov. 1, 2021).

The RTO Reserve Zone scheduled and identified an average of 720.5 MW of tier 2 synchronized reserves in 2021. Of this, an average of 524.3 MW was scheduled hourly.

Figure 10-4 and Figure 10-5 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self scheduled) from January 2020 through December 2021, for MAD Reserve Subzone and the RTO Reserve Zone. There were 33 intervals of shortage in 2019. There were 13 spinning events in 2019 but only two lasted longer than 10 minutes. There were seven intervals of shortage in 2020 and 16 spinning events with three longer than 10 minutes. In 2021, there were 19 intervals of shortage and 18 spinning events of which five were longer than 10 minutes.

Figure 10-4 MAD hourly average tier 2 synchronized reserve scheduled MW: January 2020 through December 2021

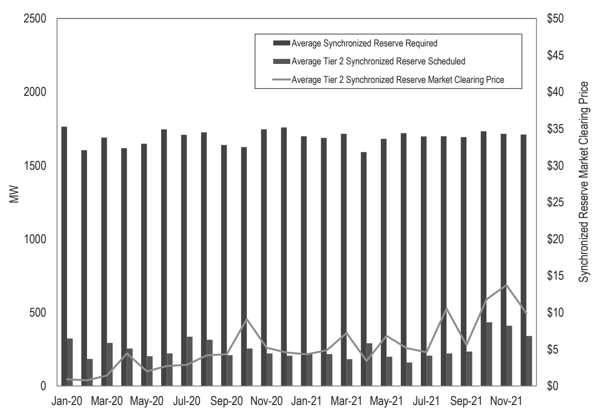
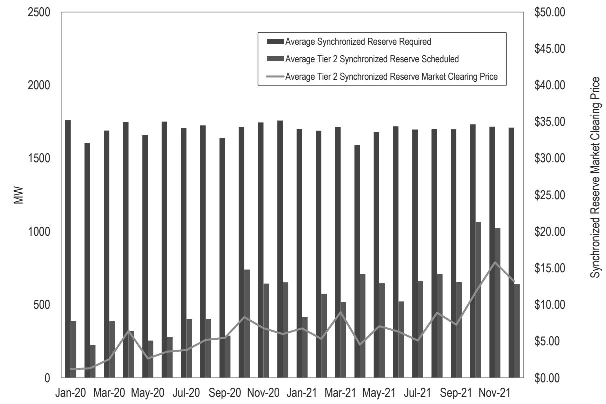


Figure 10-5 RTO hourly average tier 2 synchronized reserve scheduled MW: January 2020 through December 2021



Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2021 was 5004, which is defined as highly concentrated. In 83.0 percent of all cleared pricing intervals the maximum market share was greater than or equal to 40 percent.

The average HHI for tier 2 synchronized reserve for cleared pricing intervals of the RTO Zone Tier 2 Synchronized Reserve Market in 2021 was 3460, which is defined as highly concentrated. In 49.3 percent of cleared intervals there was a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 2.6 percent of all tier 2 synchronized reserve in 2021. In the RTO Zone, flexible synchronized reserve was 4.7 percent of all tier 2 synchronized reserve MW in 2021.

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

Market Behavior

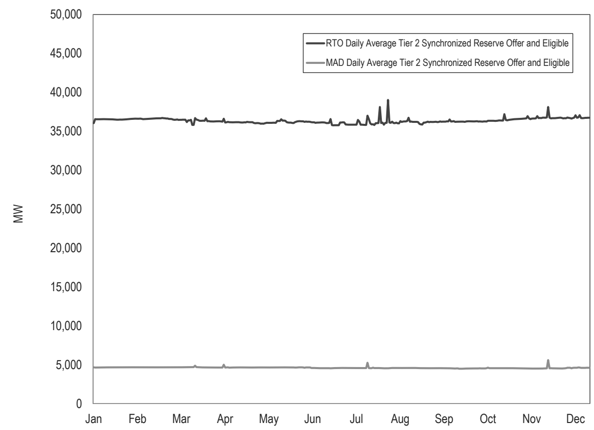
Offers

Daily cost-based offers are submitted for each unit by the unit owner. For generators the offer must include, when relevant, a tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus a markup of $7.50 per MW. The tier 1 synchronized reserve ramp rate must be greater than or equal to the real-time economic ramp rate. If the synchronized reserve ramp rate is greater than the economic ramp rate it must be justified by the submission of actual data from previous synchronized reserve events.[54] All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer quantity is limited to the economic maximum. PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times 10 minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to zero MW. Certain defined resource types are not required to offer tier 2 because they cannot reliably provide synchronized reserve. These include: nuclear, wind, solar, landfill gas and energy storage resources.[55]

Figure 10-6 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone.

PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers are made on a daily basis with hourly updates permitted. Daily offers can be changed as a result of maintenance status or physical limitations only and are required regardless of online/offline state.[56] The tier 2 synchronized reserve market is not cleared based on daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW can change significantly every hour (Figure 10-6). Changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. However, resource operators can make their units unavailable for an hour or block of hours without having to provide a reason. In 2021, synchronized reserve offers averaged 36,355.7 MW in the RTO Zone and 4,606.9 MW in the MAD Subzone.

Figure 10-6 Tier 2 synchronized reserve hourly offer and eligible volume (MW): 2021



Although tier 2 synchronized reserve has a must offer requirement, there are a large number of hours when many units make themselves unavailable for tier 2 synchronized reserve.

The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer to 0 MW.[57]

54 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 117 (September 1, 2021).
55 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 117 (Nov., 2021).
56 See *id.* ("Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT…").
57 PJM adopted a new business rule in the third quarter of 2017 to enforce compliance with the tier 2 must-offer requirement. PJM enters a zero dollar offer price for all units with a must offer obligation for tier 2 synchronized reserves.

Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes by the LPC market solution for the RTO Reserve Zone and the MAD Subzone. The tier 2 synchronized reserve market price is determined not only by the offer price of each cleared MW of tier 2, but additionally by the net cost of jointly optimizing the dispatch of energy and synchronized reserve. For each MW assigned, the clearing engines determine a product substitution price, i.e. the marginal cost of replacing the reserve MW with energy from other resources. The product substitution cost is a function of the LMPs of the MW of reserve, the marginal cost of energy for the resources providing reserves, and the minimized cost of substituted MW providing energy. At the margin, the price is the sum of the offer price plus the product substitution cost of the marginal unit(s).[58] The number of marginal units by schedule type is shown in Table 10-15.

Table 10-15 Schedule used for LOC of marginal units in RTSCED Tier 2 Synchronized Reserve Market LOC calculation: 2021

Number of Marginal Units	Percent of Marginal Units with LOC Based on Cost Schedule	Percent of Marginal Units with LOC Based on Price Schedule
164,712	8.7%	91.3%

In 2021, the RTSCED cleared the RTO tier 2 synchronized reserve market in 64.1 percent of all dispatch solutions. In all other intervals there was enough tier 1 synchronized reserve to cover the synchronized reserve requirement. For intervals when the synchronized reserve requirement could not be met with tier 1, the market cleared an average of 517.5 MW of synchronized reserve (plus 166.3 MW of demand response) at a MW weighted average price of $8.41 per hour. The tier 2 MW from both generation and load response increased beginning in October as a result of a significant decrease in estimated tier 1 MW.

The market clearing price for the MAD Subzone diverged from the RTO Zone in 45 intervals during 2021.

Supply, demand, and performance for tier 2 synchronized reserve cleared hours (price > $0) are reflected in the price of synchronized reserve (Table 10-16).

58 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 117 (Nov. 1, 2021), p. 92.

Table 10-16 RTO Zone, average SRMCP and average scheduled, tier 1 estimated and demand response MW in RT SCED market solutions: January 2020 through December 2021

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Weighted Average Dispatch Solution Reserve Market Clearing Price	Average Interval Tier 2 Generation Synchronized Reserve Purchased (MWh)	Average Interval Tier 1 Synchronized Reserve Estimated (MWh)	Average Interval Demand Response Cleared (MWh)
2020	Jan	$1.20	$1.18	322.4	2,410.7	67.2
2020	Feb	$1.30	$1.57	183.7	2,285.5	42.6
2020	Mar	$2.56	$2.26	293.8	2,142.0	92.8
2020	Apr	$6.42	$5.54	255.0	2,223.8	66.5
2020	May	$2.65	$2.68	202.5	2,130.4	52.6
2020	Jun	$3.58	$3.35	221.9	2,723.9	58.6
2020	Jul	$3.80	$3.72	335.4	2,102.5	65.3
2020	Aug	$5.19	$5.36	314.7	1,961.6	86.5
2020	Sep	$5.47	$4.25	209.6	2,054.2	79.2
2020	Oct	$8.32	$6.61	575.1	1,380.2	165.3
2020	Nov	$6.78	$4.77	502.6	1,500.4	141.4
2020	Dec	$5.99	$4.44	507.7	1,506.8	145.0
2020	Average	$4.44		327.0	2,035.2	88.6
2021	Jan	$6.77	$5.30	331.8	1,761.2	88.1
2021	Feb	$5.33	$4.25	461.5	1,845.8	136.5
2021	Mar	$8.98	$6.58	431.8	1,704.9	122.6
2021	Apr	$4.55	$3.54	545.2	1,313.3	164.5
2021	May	$7.06	$5.53	594.2	1,372.3	186.4
2021	Jun	$6.32	$5.17	465.0	1,699.5	142.7
2021	Jul	$5.10	$3.88	482.5	1,676.2	177.4
2021	Aug	$8.91	$5.97	498.9	1,766.0	206.0
2021	Sep	$7.26	$4.59	431.4	1,780.0	184.6
2021	Oct	$11.71	$8.33	778.0	1,111.3	250.1
2021	Nov	$15.80	$10.74	743.6	1,166.5	228.0
2021	Dec	$13.18	$9.98	445.5	1,617.0	108.2
2021	Average	$8.41	$6.16	517.5	1,567.8	166.3

Settlement Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost to customers, including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis) but inflexible synchronized reserve commitment occurs prior to the hour, the realized, within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the market are guaranteed to be made whole and are paid uplift credits in settlement if the SRMCP does not compensate them for their offer plus LOC.

PJM implemented fast start pricing on September 1, 2021. Between September 1, 2021 and December 31, 2021 prices were 2.1 percent higher than in the dispatch run (only intervals where the Tier 2 Synchronized Reserve price is greater than $0 are considered). The price was above zero in the RTO Zone in 38.2 percent of intervals in 2021. (Table 10-17).

Prices were significantly higher in 2021 than they were in 2020 because of increases in the synchronized reserve requirement, higher fuel costs, and fast start pricing (Table 10-17). The MW weighted synchronized reserve market clearing price is computed for hours when the price was above $0. The market clearing solution includes a constraint that forces all remaining synchronized reserve to be cleared from the MAD Subzone (Figure 10-1) when one of the constraints defining MAD binds. RTO/MAD prices diverged in only 45 intervals in 2021. In 2021, the MW weighted average tier 2 synchronized reserve clearing price was $8.87 in the RTO Zone and $7.32 in the MAD Subzone.

Table 10-17 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: 2021

Year	Month	Tier 2 Generation and DSR Credited MWh	Tier 2 SRMCP Credits	LOC Credits	Weighted Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price / Cost Ratio
2021	Jan	313,931	$2,331,218	$286,087	$6.77	$8.34	81.3%
2021	Feb	256,201	$1,603,753	$1,062,361	$5.33	$10.41	51.2%
2021	Mar	329,137	$3,255,393	$1,392,791	$8.98	$14.12	63.6%
2021	Apr	343,354	$1,831,478	$662,382	$4.55	$7.26	62.6%
2021	May	390,619	$3,283,465	$1,216,534	$7.06	$11.52	61.3%
2021	Jun	306,172	$2,293,837	$1,262,148	$6.32	$11.61	54.4%
2021	Jul	267,256	$1,682,350	$1,255,201	$5.10	$10.99	46.4%
2021	Aug	245,668	$2,738,144	$2,428,284	$8.91	$21.03	42.3%
2021	Sep	198,624	$1,857,005	$1,468,205	$9.86	$16.74	43.3%
2021	Oct	413,081	$6,237,138	$2,467,669	$12.00	$21.07	55.6%
2021	Nov	391,178	$7,530,370	$1,756,684	$15.11	$23.74	66.6%
2021	Dec	267,476	$4,165,825	$899,034	$16.46	$18.94	69.6%
2021		3,722,698	$38,809,977	$16,157,380	$8.87	$14.65	60.6%

Table 10-18 shows the effect of fast start pricing on the synchronized reserve market's monthly weighted average market clearing price in 2021. The weighted average market clearing price for each month is consistently higher in the pricing run then in the dispatch run.

Table 10-18 Comparison of fast start and dispatch pricing components: September 2021 through December 2021

Month	Pricing Method	Weighted Average Market Clearing Price
Sep	Fast Start	$9.86
	Dispatch	$9.67
Oct	Fast Start	$12.00
	Dispatch	$11.84
Nov	Fast Start	$15.11
	Dispatch	$14.76
Dec	Fast Start	$16.46
	Dispatch	$16.10

Performance

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[59] Tier 2 resource owners are paid for being available but are not paid based on the actual response to a synchronized reserve event. The MMU has identified and quantified the actual performance of scheduled tier 2 synchronized reserve resources when called on to deliver during synchronized reserve events since 2011.[60] When synchronized reserve resources self schedule or clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full scheduled tier 2 MW during a synchronized reserve event. Actual synchronized reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after start of the event, and initial output is the lowest output between one minute before the event and one minute after the event.[61] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. Penalties are assessed for failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

Tier 2 performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. For the spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. In 2017, the response rate was 87.6 percent. In 2018, the response rate was 74.2 percent. In 2019, the response rate was 86.8 percent. In 2020, there were five spinning events 10 minutes or longer with an average response rate of 59.5 percent of scheduled tier 2 MW. In 2021 there were five spinning events lasting 10 minutes or longer. They had a tier 2 synchronized reserve response rate of 76.9 percent. Actual participant performance means that the penalty structure is not adequate to incent performance.

The penalty structure when a tier 2 resource fails to respond fully to a spinning event includes two components. The resource forfeits all SRMCP credits and LOC credits in the amount of the MW shortage for the day on which the event occurred. The resource also receives a penalty for all hours in the Immediate Past Interval (IPI) in the amount of MW it falls short of its scheduled MW. The penalty is applied only to the SRMCP credits, not to the LOC credits. The penalty period is calculated as the lesser of the average number

59 See *id.* at 98.
60 See *2011 State of the Market Report for PJM*, Vol. II, Section 9, "Ancillary Services," at 250.
61 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 117 (Nov. 1, 2021).

of days between spinning events over the past two years (ISI) or the number of days since the resource last failed to respond fully. There are several problems with this penalty structure. Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from a different unit to reduce an underresponse penalty.[62] The IPI uses the last spinning event when the resource did comply. But for all spin events less than 10 minutes, compliance is automatically counted as 100 percent. This incorrectly truncates the IPI. The penalty applies only to the SRMCP credits not the LOC credits. But most credits awarded are for LOC.

Under the current penalty structure it is possible for a resource to not respond to any spin events and yet be paid for providing tier 2. The current penalty structure for tier 2 synchronized reserve nonperformance is not adequate to provide appropriate performance incentives.

The IPI is defined as the number of days between spinning events, regardless of duration. This definition artificially shortens the period since the last requirement to perform. The MMU continues to recommend that the IPI be defined as the number of days between spinning events 10 minutes or longer (Table 10-19). In 2021, PJM had 16 spinning events. Five of those events were 10 minutes or longer, March 9, April 30, May 26, August 23, and November 12. The previous 10 minute event was on December 16, 2020. If only events 10 minutes or longer were considered, the IPI would increase to 70 days from its current level of 25 days. Use of the currently defined average IPI is not appropriate. The penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed because performance is only measured for events 10 minutes or longer. Even using the proposed IPI the penalties may be insufficient to ensure response. A tier 2 shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall.

Table 10-19 lists the total tier 2 synchronized reserve shortfall penalties for 2021 for lack of tier 2 response both by the current PJM penalty structure and the penalties if PJM adopted the proposed MMU penalty structure.

62 See PJM "Manual 28: Operating Agreement Accounting,"§ 6.3 Charges for Synchronized Reserve, Rev. 85 (September 1, 2021.)

Table 10-19 Comparison of tier 2 shortfall penalties under current IPI vs. MMU recommended IPI: 2021

Penalty Type	Current PJM Penalty	MMU Recommended Penalty
Day Of Event	$55,412	$79,900
Retroactive Charges	$981,148	$3,164,326
Total Penalties	$1,036,559	$3,244,226

Including aggregate responses from all online resources weakens the incentive to perform and creates an incentive to withhold reserves from other resources. Synchronized reserve commitment is unit specific, so the obligation to respond should also be unit specific. Any potentially offsetting response from an affiliated tier 1 resource should have been included as part of the reserves in the tier 1 estimate. Any potentially offsetting response from a tier 2 resource should have been included in that tier 2 offer.

The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event.

Spinning event response data as reported by PJM in its Operating Committee meetings is shown in Table 10-20. The tier 1 estimate is from the most recent RT SCED market solution. The tier 1 estimate includes estimated ramp only from the units that are eligible and excludes resources that have ramp available but are not part of the estimate.

Tier 1 synchronized reserve that responds to a spinning event receives a bonus payment of $50 per MWh, based on a calculation using SCADA data, regardless of whether PJM included those reserves in the estimate.

Table 10-20 shows synchronized reserve event response compliance for tier 1 and tier 2 reserves as reported by PJM, using only response from tier 1 estimated and tier 2 cleared reserves. Actual synchronized reserve response is the total increase in MW from all resources from the moment the spinning event is called to 10 minutes after. To determine the actual tier 1 response, the calculation would subtract tier 2 response, changes in assigned regulation output (net compliance level to both RegA and RegD), and changes to net power flow across PJM's interface boundary. The overall response to spinning events is adequate or more than adequate to meet NERC requirements. PJM not only corrects the ACE disturbance that led to the event but over corrects.

In eight of the 10 spinning events the ACE recovers not just to the NERC required level (which is the lesser of 0 or the value before the disturbance which caused the event) but overshoots.

Table 10-20 Synchronized reserve events 10 minutes or longer, tier 1 and tier 2 response compliance as reported by PJM, RTO Reserve Zone: January 2019 through December 2021

Spin Event (Day, EPT Time)	Duration (Minutes)	Tier 1 Estimate (Market Solution MW Adj by DGP)	Response from Tier 1 DGP Estimated (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	DGP Estimated Tier 1 Response Percent	Tier 2 Response Percent
Sep 23, 2019 12:07	11	1,485.1	1,212.1	723.2	632.1	91.1	81.6%	87.4%
Oct 1, 2019 14:56	11	265.4	143.7	1,177.4	1,016.4	161.0	54.1%	86.3%
2019 Average	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%
Feb 18, 2020 20:15	10	2,216.1	1,434.8	40.0	1.7	38.3	64.7%	4.3%
Jul 6, 2020 21:22	10	1,464.0	526.1	479.7	415.1	64.6	35.9%	86.5%
Jul 25, 2020 16:39	11	868.4	421.6	302.3	264.8	37.5	48.5%	87.6%
Sep 10, 2020 00:29	10	1,275.4	453.6	782.6	782.6	0.0	35.6%	100.0%
Dec 16, 2020 16:49	10	268.4	196.9	527.6	413.2	114.4	73.4%	78.3%
2020 Average	10	1,218.5	606.6	426.4	375.5	51.0	49.7%	59.5%
Mar 9, 2021 07:50	10	1,354.9	635.4	884.0	540.8	343.2	46.9%	61.2%
Apr 30, 2021 16:30	12	1,487.6	610.2	508.3	407.2	101.1	41.0%	80.1%
May 26, 2021 10:17	10	1,138.4	811.0	685.2	600.2	85.0	71.2%	87.6%
Aug 23, 2021 16:44	18	879.8	597.5	896.2	667.1	229.1	67.9%	74.4%
Nov 12, 2021 17:25	12	510.0	606.7	890.7	714.6	176.1	119.0%	80.2%
2021 Average	12	1,074.1	652.2	772.9	586.0	186.9	69.2%	76.7%

Until April 2019, PJM's ASO market solution software allowed operators to bias the inflexible tier 2 synchronized reserve solution by forcing the software to assume a different tier 1 MW value than the actual estimate. PJM, in response to the MMU recommendation, no longer uses tier 1 biasing in any of its market solutions. Biasing means manually modifying (decreasing or increasing) the tier 1 synchronized reserve estimate of the market solution.

Tier 1 biasing was never referenced in PJM manuals or any public document. PJM could resume tier 1 biasing at its discretion. Although tier 1 biasing has been discontinued, PJM can and does still deselect tier 1 resources based on PJM judgment. The impact of tier 1 deselection can be very significant (Table 10-21 and Table 10-22).

Table 10-21 Units deselected for tier 1 by market solutions but awarded credits for actual response: 2021

Spinning Event	Number Units Deselected by RTSCED Awarded T1 Credits	Total T1 Credits Awarded	Percent of T1 Credits Awarded to Units Deselected for T1	Total T1 Credited MWh	Percent of T1 MW Awarded Credits But Deselected
1/24/2021 3:22	280	$6,592	46.0%	1,582.2	46.0%
3/9/2021 12:50	938	$14,658	46.4%	1,918.9	85.0%
4/13/2021 20:05	374	$18,496	38.3%	4,439.0	38.3%
4/30/2021 20:30	705	$20,868	44.5%	2,921.5	76.3%
5/26/2021 14:17	864	$21,233	49.0%	5,095.8	49.0%
6/21/2021 5:54	545	$10,301	28.9%	2,119.0	33.7%
6/23/2021 3:33	354	$5,735	50.5%	1,376.5	50.5%
7/21/2021 18:28	516	$3,379	37.0%	811.1	37.0%
7/25/2021 16:17	652	$12,186	50.9%	2,924.6	50.9%
8/23/2021 16:44	1,936	$28,450	52.8%	6,828.0	52.8%
8/24/2021 10:38	704	$16,686	47.8%	4,004.7	47.8%
9/27/2021 16:56	562	$119,934	72.6%	3,058.7	67.8%
10/11/2021 13:23	881	$16,731	55.3%	4,015.5	55.3%
10/16/2021 5:30	452	$9,391	35.1%	2,254.0	35.1%
11/12/2021 17:25	646	$21,981	58.5%	5,275.5	58.5%
11/30/2021 9:40	540	$14,484	45.3%	3,476.1	45.3%
11/30/2021 12:57	814	$18,244	51.4%	4,378.5	51.3%
12/8/2021 9:04	894	$6,857	52.3%	1,645.6	52.3%
2021 Averages	703	$20,345	47.9%	3,229.2	51.8%

Table 10-22 Comparison of market solution tier 1 estimate, tier 1 response with PJM Settlements tier 1 MW credited: January 2020 through December 2021

Start Time	Duration (Minutes)	PJM Market Solution DGP Estimated Tier 1 Estimate MW	PJM Market Solution DGP Estimated Tier 1 Response MW	PJM Settlements Tier 1 Credited Response MWh
Jan 20, 2020 14:06	7.8	1,903.6	765.9	1,306.3
Jan 23, 2020 16:17	8.7	2,084.6	1,073.0	1,860.4
Feb 7, 2020 12:06	6.4	1,233.0	730.2	2,883.9
Feb 8, 2020 03:44	8.4	1,961.4	826.1	1,517.6
Feb 10, 2020 20:15	9.6	1,333.3	824.3	1,573.8
Feb 18 2020 11:16	10.0	2,216.1	1,434.8	2,528.6
Mar 8, 2020 05:17	5.6	1,541.4	660.1	843.5
Apr 13, 2020 19:53	7.9	433.0	207.2	886.5
May 3, 2020 12:23	6.6	4,154.4	1,369.6	2,260.5
Jul 6, 2020 21:22	10.4	1,464.0	526.1	1,554.5
Jul 24, 2020 01:03	9.9	1,562.7	852.8	1,762.7
Jul 25, 2020 16:39	11.7	868.4	421.6	961.5
Sep 10, 2020 00:19	9.5	1,275.4	453.6	1,417.0
Oct 10, 2020 18:52	7.7	2,134.3	1,234.3	2,187.8
Oct 12, 2020 04:29	9.3	1,625.8	670.5	1,229.2
Nov 13, 2020 11:36	5.9	1,687.9	882.4	1,682.8
Dec 16, 2020 16:38	10.0	268.4	196.9	1,213.0
Jan 25, 2021 03:32	6.5	2,134.5	577.9	1,165.0
Mar 9, 2021 12:50	10.8	1,354.9	635.4	1,715.9
Apr 13, 2021 20:05	8.8	2,093.4	975.6	2,534.3
Apr 30, 2021 20:30	11.6	1,487.6	610.2	2,143.5
May 26, 2021 14:17	10.0	1,138.4	811.0	2,618.6
Jun 21, 2021 05:54	6.9	2,340.8	1,764.1	1,806.7
Jun 23, 2021 03:33	4.7	2,277.0	1,367.8	1,376.5
Jul 21, 2021 22:27	5.0	837.8	290.8	881.3
Jul 25, 2021 20:16	6.0	708.7	418.8	2,117.9
Aug 23, 2021 20:24	17.6	879.8	597.5	2,050.4
Aug 24, 2021 14:37	8.1	903.7	658.3	2,615.9
Sep 27, 2021 20:56	8.4	679.5	385.1	3,058.7
Oct 11, 2021 13:23	9.3	1,215.9	577.8	4,015.5
Oct 16, 2021 05:30	7.7	1,060.4	669.1	2,254.0
Nov 12, 2021 17:25	12.1	510.0	606.7	5,275.5
Nov 30, 2021 9:40	9.8	899.2	678.3	3,476.1
Nov 30, 2021 12:57	8.5	948.6	452.3	4,378.5
Dec 8, 2021 09:04	7.8	481.6	288.8	1,645.6

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[63] [64] A disturbance is defined as loss of the lesser of 900 MW or 80 percent of the most severe single contingency within 60 seconds. In the absence of a disturbance, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to 30 minutes. When the need is for reserve extending past 30 minutes, secondary reserve is the appropriate source of the response. The use of synchronized reserve is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicate no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in the absence of disturbances.

From January 2017 through December 2021, PJM experienced 82 synchronized reserve events (Table 10-23), approximately one and a half events per month. During this period, synchronized reserve events had an average duration of 9.0 minutes.

63 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.
64 See PJM "Manual 12: Balancing Operations," Rev. 43 (June 6, 2021) § 4.1.2 Loading Reserves.

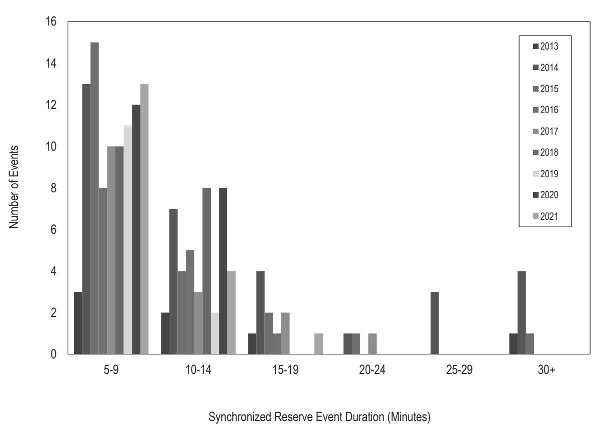
Table 10-23 Synchronized reserve events: January 2017 through December 2021[65]

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-08-2017 03:21	RTO	7	JAN-01-2018 02:41	RTO	7	JAN-22-2019 22:30	RTO	8
JAN-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13	JAN-31-2019 01:26	RTO	5
JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	9	JAN-31-2019 09:26	RTO	9
JAN-15-2017 20:13	RTO	8	APR-12-2018 13:28	RTO	10	FEB-25-2019 00:25	RTO	9
JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6	MAR-03-2019 12:31	RTO	9
FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9	MAR-06-2019 22:06	RTO	9
FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11	JUL-27-2019 23:31	RTO	7
FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7	AUG-11-2019 12:14	RTO	8
MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13	SEP-03-2019 13:39	MAD	9
APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8	SEP-23-2019 16:06	RTO	11
MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6	OCT-01-2019 18:56	RTO	11
JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7	DEC-11-2019 21:08	RTO	8
JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11	DEC-18-2019 15:07	RTO	9
SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7			
SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7			
SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8			
			SEP-30-2018 11:29	RTO	11			
			OCT-30-2018 10:40	RTO	11			

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-20-2020 14:06	MAD	8	JAN-24-2021 22:32	RTO	6
JAN-23-2020 16:17	RTO	9	MAR-9-2021 07:51	RTO	11
FEB-07-2020 12:06	RTO	6	APR-13-2021 20:05	RTO	9
FEB-08-2020 03:44	RTO	8	APR-30-2021 20:30	RTO	12
FEB-10-2020 20:15	RTO	9	MAY-26-2021 14:17	RTO	10
FEB-18-2020 11:16	RTO	10	JUN-21-2021 05:54	RTO	7
MAR-08-2020 05:17	MAD	5	JUN-23-2021 03:33	RTO	5
APR-13-2020 20:01	RTO	8	JUL-21-2021 18:28	RTO	5
MAY-03-2020 12:29	RTO	6	JUL-25-2021 16:17	RTO	6
JUL-06-2020 21:22	RTO	10	AUG-23-2021 16:44	RTO	18
JUL-24-2020 01:03	RTO	9	AUG-24-2021 10:38	RTO	8
JUL-25-2020 16:39	MAD	11	SEP-27-2021 16:56	RTO	8
SEP-10-2020 00:19	RTO	10	OCT-11-2021 09:23	RTO	9
OCT-10-2020 18:52	RTO	8	OCT-16-2021 01:30	RTO	8
OCT-12-2020 04:29	RTO	9	NOV-12-2021 13:25	RTO	12
NOV-13-2020 07:46	RTO	6	NOV-30-2021 05:40	RTO	9
DEC-16-2020 16:38	MAD	10	NOV-30-2021 09:57	RTO	9
			DEC-8-2021 05:04	RTO	7

Figure 10-7 shows spin event durations over the past five years.

Figure 10-7 Synchronized reserve events duration distribution curve: January 2013 through December 2021



65 For full history of spinning events, see the *2019 State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.

Nonsynchronized Reserve Market

Nonsynchronized reserve consists of MW available within 10 minutes but not synchronized to the grid. Startup time for nonsynchronized reserve resources is not subject to testing and is based on parameters in offers submitted by resource owners. There is no defined requirement for nonsynchronized reserves. It is available to meet the primary reserve requirement. Generation resources that have designated their entire output as emergency are not eligible to provide nonsynchronized reserves. Generation resources that are not available to provide energy are not eligible to provide nonsynchronized reserves.

The market mechanism for nonsynchronized reserve does not include any direct participation by market participants. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers. Since nonsynchronized reserve is a lower quality product, its clearing price is less than or equal to the synchronized reserve market clearing price. In most hours, the nonsynchronized reserve clearing price is zero.

Market Structure

Demand

Demand for primary reserve is established by PJM as one and a half times the largest contingency. Demand for primary reserve is calculated dynamically in every synchronized and nonsynchronized reserve market solution. After filling the synchronized reserve requirement the balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. In practice this means that the primary reserve requirement minus the scheduled synchronized reserve is the nonsynchronized requirement for the interval. PJM may increase the primary reserve requirement to cover times when a single contingency could cause an outage of several generating units or in times of high load conditions causing operational uncertainty.[66]

The average scheduled hourly nonsynchronized reserve in the RTO Zone in 2021 was 1,067.3 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve was 1,059.6 MW.

Supply

Figure 10-2 shows that when tier 1 synchronized reserve does not fully meet the synchronized reserve requirement, then most of the primary reserve requirement (blue line) in excess of the synchronized reserve requirement (purple line) is satisfied by nonsynchronized reserve (green area).

There are no offers for nonsynchronized reserve. The market solution considers the available supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have set themselves as unavailable or have set their output to be emergency only will not be considered. The market solution considers the offered MW to be the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. The market supply curve is constructed from the nonsynchronized units' opportunity cost of providing reserves. PJM and generation owners may agree upon exceptions to the requirements.

Nonsynchronized reserve resources are scheduled economically based on estimated LOC until the Primary Reserve requirement is filled. The nonsynchronized reserve market clearing price is determined every five minutes based on the LOC of the marginal unit. When a unit clears the nonsynchronized reserve market and is scheduled, it is committed to remain offline and available to provide 10 minute reserves.

Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles that can start in 10 minutes or less, and diesels.[67] In 2021, an average of 1,067.3 MW of nonsynchronized reserve was scheduled per five minute interval out of 1,414.6 eligible MW as part of the primary reserve requirement in the RTO Zone. If only intervals when the price was greater than $0 are looked at, then an average of 666.9 MW of

66 See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 117 (Nov. 1, 2021).

67 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 117 (Nov. 1, 2021)

nonsynchronized reserve is scheduled out of 990.3 MW available.

In 2021, CTs provided 83.9 percent of scheduled nonsynchronized reserve (Table 10-24). Natural gas was the primary fuel for nonsynchronized reserve.

Table 10-24 Supply of nonsynchronized reserve by fuel and unit type: 2021

Unit / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	44.1%	25.9%
CT - Oil	39.6%	61.5%
Hydro - Run of River	15.6%	11.9%
Hydro - Pumped Storage	0.4%	0.2%
CT - Other	0.2%	0.4%
RICE - Oil	0.1%	0.2%
Battery	0.0%	0.0%
Combined Cycle	0.0%	0.0%
Distributed Gen	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
RICE - Natural Gas	0.0%	0.0%
RICE - Other	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Coal	0.0%	0.0%
Steam - Natural Gas	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Steam - Other	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in 2021. Table 10-25 shows the percent of dispatch solutions with a real-time nonsynchronized reserve market clearing price greater than $0.01 that failed the three pivotal supplier test. In 2021, on average, there were 165 dispatch cases each month with a real-time price above $0.01, of which 99.6 percent had at least one pivotal supplier. In 2021, 99.96 percent of all tested cases, or 2,486 out of 2,487, had at least one pivotal supplier.

Table 10-25 Percent of dispatch solutions with NSRMCP greater than $0.01 failing the three pivotal supplier test: 2021

Year	Month	Number of Dispatch Cases NSR MCP > $0.01	Percent of Dispatch Cases NSR MCP > $0.01 Pivotal
2021	Jan	30	100.0%
2021	Feb	149	100.0%
2021	Mar	56	100.0%
2021	Apr	192	100.0%
2021	May	615	100.0%
2021	Jun	187	100.0%
2021	Jul	92	100.0%
2021	Aug	106	100.0%
2021	Sep	108	100.0%
2021	Oct	813	100.0%
2021	Nov	477	100.0%
2021	Dec	22	95.5%
2021	Average	165	99.6%

Price

The settled price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

Figure 10-8 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average credited MW for the RTO Zone. In 2021, the weighted average nonsynchronized market clearing price for all intervals was $0.31 per MW. The average nonsynchronized reserve credited was 1,067.3 MW.

Figure 10-8 Daily average weighted RTO Zone nonsynchronized reserve market clearing price and MW purchased: 2021

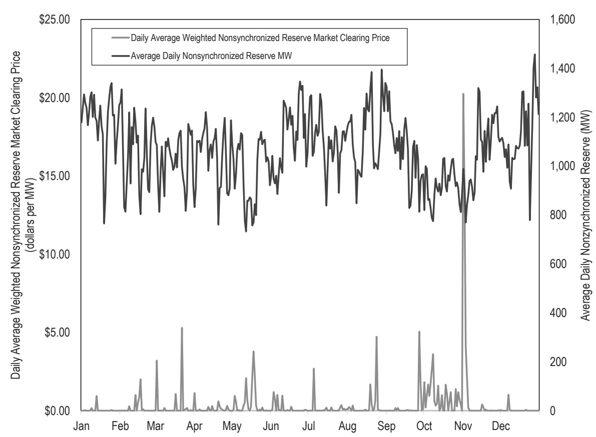


Table 10-26 shows the effect of fast start pricing on the nonsynchronized reserve market's monthly weighted average market clearing price in 2021. The weighted average market clearing price for each month is consistently higher in the pricing run than in the dispatch run.

Table 10-26 Comparison of fast start and dispatch and pricing components: 2021

Month	Pricing Method	Weighted Average Market Clearing Price
Sep	Fast Start	$0.28
	Dispatch	$0.24
Oct	Fast Start	$1.26
	Dispatch	$0.97
Nov	Fast Start	$2.74
	Dispatch	$2.12
Dec	Fast Start	$0.10
	Dispatch	$0.04

Price and Cost

As a result of changing grid conditions, load forecasts, incorrect LMP and lost opportunity cost projections, and unexpected generator performance, prices frequently do not cover the full LOC of each resource. All resources cleared in the market are guaranteed to be made whole and are paid uplift credits if the NSRMCP does not fully compensate them. When real-time LMP is greater than the generator's incremental energy offer at economic minimum, then an LOC is paid, even if LMP revenue would not have covered the unit's start and no load costs.[68]

The full cost to customers of nonsynchronized reserve credits, including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-27). The closer the price to cost ratio comes to one, the more compensation is provided

In 2021, the average price of nonsynchronized reserve was $0.48 per MW. The average credit for nonsynchronized reserve was $1.80 per MW.

Resources that are not synchronized to the grid are generally off because it is not economic for them to produce energy. A resource scheduled for nonsynchronized reserve is obligated to remain unsynchronized even if its LMP increases above its energy offer. In that case, PJM pays the unit LOC.

68 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 117 (Nov. 1, 2021).

Table 10-27 RTO zone nonsynchronized reserve MW, charges, price, and cost: January 2020 through December 2021

Market	Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2020	Jan	775,929	$377,336	$0.00	$0.49	NA
RTO Zone	2020	Feb	758,614	$138,939	$0.00	$0.18	NA
RTO Zone	2020	Mar	806,059	$170,156	$0.00	$0.21	NA
RTO Zone	2020	Apr	665,747	$644,306	$0.02	$0.97	2.1%
RTO Zone	2020	May	774,183	$425,791	$0.01	$0.55	1.1%
RTO Zone	2020	Jun	619,391	$649,601	$0.11	$1.05	10.4%
RTO Zone	2020	Jul	767,222	$648,118	$0.24	$0.84	28.4%
RTO Zone	2020	Aug	799,233	$1,106,678	$0.49	$1.38	35.4%
RTO Zone	2020	Sep	761,617	$750,028	$0.02	$0.98	2.0%
RTO Zone	2020	Oct	773,420	$1,588,183	$0.93	$2.05	45.2%
RTO Zone	2020	Nov	725,048	$809,177	$0.36	$1.12	31.9%
RTO Zone	2020	Dec	851,859	$921,357	$0.07	$1.08	6.4%
RTO Zone	2020	Total	9,078,323	$8,229,669	$0.19	$0.91	18.10%
RTO Zone	2021	Jan	878,568	$531,437	$0.05	$0.60	8.3%
RTO Zone	2021	Feb	706,486	$600,304	$0.27	$0.85	31.8%
RTO Zone	2021	Mar	760,807	$1,612,035	$0.34	$2.12	16.0%
RTO Zone	2021	Apr	752,203	$422,508	$0.14	$0.56	25.8%
RTO Zone	2021	May	725,702	$1,795,780	$0.53	$2.47	21.3%
RTO Zone	2021	Jun	801,295	$942,343	$0.19	$1.18	16.3%
RTO Zone	2021	Jul	822,174	$796,675	$0.16	$0.97	16.9%
RTO Zone	2021	Aug	818,194	$2,612,797	$0.39	$3.19	12.2%
RTO Zone	2021	Sep	763,901	$1,552,338	$0.33	$2.03	16.3%
RTO Zone	2021	Oct	680,051	$1,428,601	$1.05	$2.10	50.1%
RTO Zone	2021	Nov	760,821	$2,908,425	$1.65	$3.82	43.2%
RTO Zone	201	Dec	832,767	$1,571,760	$0.05	$1.89	2.8%
RTO Zone	2021	Total	9,302,967	$16,775,003	$0.43	$1.80	23.9%

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not currently have a defined reserve product to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer based market for 30 minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market is required to be available for dispatch in real time.[69]

Market Structure

Supply

Both generation and demand resources are eligible to offer DASR. DASR offers consist of price only. Available DASR MW are calculated by the market clearing engine. DASR MW are the lesser of the energy ramp rate per minute for online units times 30 minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in 30 minutes, the DASR quantity is the economic maximum. In 2021, the DASR hourly average purchased was 4,919.6 MW.[70]

PJM excludes resources that cannot reliably provide reserves in real time from participating in the DASR market. Such resources include nuclear, run of river hydro, self-scheduled pumped hydro, wind, solar, and energy storage resources.[71] The intent is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. Owners of excluded resources may request an exemption from their default noneligibility.

69 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 117 (Nov. 1, 2021).
70 The average hourly available DASR MW are modified from previously reported values because of a calculation error which has been fixed.
71 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 117 (Nov. 1, 2021).

Of the scheduled DASR MW cleared in 2021, 80.7 percent was from CTs (Table 10-28).

Table 10-28 Scheduled DASR by fuel and unit type: 2021

Unit / Fuel Type	Percentage of DASR MW	Percentage of DASR Credits
CT - Natural Gas	62.2%	56.1%
CT - Oil	18.5%	20.5%
Hydro - Pumped Storage	11.2%	6.0%
Combined Cycle	4.9%	9.5%
Steam - Coal	2.6%	3.9%
Steam - Natural Gas	0.3%	2.6%
RICE - Oil	0.2%	0.9%
RICE - Other	0.1%	0.4%
RICE - Natural Gas	0.1%	0.1%
Steam - Other	0.0%	0.1%
Steam - Oil	0.0%	0.0%
Nuclear	0.0%	0.0%
CT - Other	0.0%	0.0%
Battery	0.0%	0.0%
Distributed Gen	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Hydro - Run of River	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Demand

Secondary reserve (30 minute reserve) requirements are determined by PJM for each reliability region. In the ReliabilityFirst (RFC) region, secondary reserve requirements are calculated based on historical under forecasted load rates and generator forced outage rates.[72] The DASR requirement is calculated daily and is equal to the peak load forecast for the ReliabilityFirst region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error, plus Dominion's share of the VACAR contingency reserve commitment. From November 1, 2020 through October 31, 2021, the day-ahead scheduling reserve requirement was 4.75 percent of the peak load forecast. This was based on a 2.16 percent load forecast error component and a 2.59 percent forced outage rate component. Effective November 1, 2021, through October 31, 2022, the day-ahead scheduling reserve requirement is 4.40 percent of the peak load forecast, based on a 2.03 percent LFE component and a 2.38 percent FOR component. The DASR requirement is applicable for all hours of the operating day.

The DASR requirement can be increased by PJM operators under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[73] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[74] The SCD factor is calculated separately for the winter (November through March) and summer (April through October) seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year. For November 2020 through October 2021, the SCD values were 2.12 percent for winter and 4.72 percent for summer. For November 2021 through October 2022, the SCD values are 5.84 percent for winter and 4.06 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[75] PJM has defined the reasons for conservative operations to include, potential fuel delivery issues, forest/brush fires, extreme weather events, environmental alerts, solar disturbances, unknown grid operating state, physical or cyber attacks.[76] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand in 516 hours during 2021.

The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. The MMU further recommends that PJM attach a reason code to all hours when adjusted fixed demand is dispatched.

Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-29. Table 10-29 shows the percent of intervals with a day-ahead scheduling reserve market clearing price greater than $0.01 that failed the three pivotal supplier test. In 2021, on average, there were 97 testable intervals each month, of which 94.0 percent had at least one pivotal supplier.

72 See PJM "Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev.82 (Jan. 1, 2022).

73 PJM. "Energy and Reserve Pricing & Interchange Volatility Final Proposal Report," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-04-erpiv-final-proposal-report.ashx>.

74 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement. Rev. 117 (Nov. 1, 2021)

75 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 117 (Nov. 1, 2021).

76 See PJM "Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 82 (Jan. 1, 2022).

Table 10-29 DASR market three pivotal supplier test results and number of hours with DASR MCP above $0.01: January 2020 through December 2021

Year	Month	Number of Hours DASR MCP > $0.01	Percent of Hours DASR MCP > $0.01 Pivotal
2020	Jan	3	100.0%
2020	Feb	2	100.0%
2020	Mar	1	100.0%
2020	Apr	0	NA
2020	May	24	100.0%
2020	Jun	142	88.0%
2020	Jul	321	66.4%
2020	Aug	212	94.3%
2020	Sep	89	100.0%
2020	Oct	170	98.8%
2020	Nov	70	100.0%
2020	Dec	69	100.0%
2020	Average	92	95.2%
2021	Jan	15	100.0%
2021	Feb	26	100.0%
2021	Mar	23	100.0%
2021	Apr	93	98.9%
2021	May	79	87.3%
2021	Jun	151	78.1%
2021	Jul	148	95.9%
2021	Aug	153	84.3%
2021	Sep	131	86.3%
2021	Oct	171	98.8%
2021	Nov	140	98.6%
2021	Dec	33	100.0%
2021	Average	97	94.0%

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR market.[77] Units that do not offer have their offers set to $0.00 per MW during the day-ahead market clearing process.

Economic withholding remains an issue in the DASR market. The marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. In 2021, 45.3 percent of generation units offered DASR at a daily price above $0.00 per MW. In 2021, 17.8 percent of daily offers were above $5.00 per MW.

The MMU recommends that market solutions for the DASR market be based on opportunity cost only in order to eliminate economic withholding.

Market Performance

In 2021, the DASR market cleared at a price above $0.00 per MW in 16.4 percent of all hours. The weighted average DASR price for all cleared hours was $0.24 per MW. The average cleared MW in all hours was 4,389.5 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 5,135.2 MW. The highest DASR price in 2021 was $48.67 per MW for one hour on August 25.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market. Table 10-30 shows the use of AFD in previous years. In 2021, AFD hours were only used in the months of May, June, July, August, and September, as seen in Table 10-31. The resulting differences in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. Table 10-32 shows the differences in price and MW between AFD hours and non-AFD hours in 2021.

Table 10-30 Hours with Adjusted Fixed Demand (AFD) added to the normal DASR requirement: 2015 through 2020

Year	Number of Hours with AFD	Normal Requirement as Percentage of Forecast Load
2015	367	5.9%
2016	522	5.7%
2017	336	5.5%
2018	598	5.3%
2019	447	5.3%
2020	430	5.1%

Table 10-31 Hours with Adjusted Fixed Demand (AFD) and average increase in DASR requirement: 2021

Year	Month	Number of Hours with AFD	Average Increase in Requirement
2021	Jan	0	NA
2021	Feb	0	NA
2021	Mar	0	NA
2021	Apr	0	NA
2021	May	24	61.4%
2021	Jun	119	58.7%
2021	Jul	124	26.3%
2021	Aug	201	23.9%
2021	Sep	48	61.2%
2021	Oct	0	NA
2021	Nov	0	NA
2021	Dec	0	NA
2021	Total	516	37.7%

77 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 117 (Nov. 1, 2021).

Table 10-32 Impact of Adjusted Fixed Demand on DASR prices and demand: 2021

Metric	Number of Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All hours	8,760	$0.24	4,724.3
All hours when DASRMCP > $0	1,444	$1.27	5,314.3
All hours when AFD used	516	$1.88	7,868.2

While the new rules allow PJM operators' substantial discretion to add to DASR demand for a variety of reasons, the rationale for each specific increase is not always clear. The MMU recommends that PJM Market Operations attach a reason code to every hour in which PJM operators add additional DASR MW above the default DASR hourly requirement. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW.

Comparing the Normal Hour column against the AFD Hour column for five metrics (Table 10-33) shows that the use of AFD for 516 hours in the 2021 significantly increased the cost of DASR. Table 10-33 shows that the cost increase was a result of a substantial increase in DASR MW cleared. The average DASR clearing price in 2021 was $1.27 for hours when the clearing price was above $0.00 and $3.51 during hours when the clearing price was above $0.00 and adjusted fixed demand was invoked by PJM Dispatch.

Table 10-33 DASR market, regular hours vs. adjusted fixed demand hours with price greater than $0: 2021

		Number of Hours DASRMCP > $0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2020	Jan	3	NA	$0.10	NA	111,016	NA	4,939	NA	$487	NA
2020	Feb	3	NA	$0.10	NA	109,218	NA	5,320	NA	$508	NA
2020	Mar	1	NA	$0.19	NA	92,458	NA	4,532	NA	$861	NA
2020	Apr	0	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	May	31	NA	$0.29	NA	96,413	NA	4,711	NA	$1,364	NA
2020	Jun	124	32	$0.57	$2.60	111,577	107,687	5,345	11,033	$3,072	$28,688
2020	Jul	122	211	$1.43	$3.81	121,825	124,278	5,764	9,717	$8,243	$37,033
2020	Aug	206	17	$0.78	$7.59	117,929	121,901	5,649	10,917	$4,394	$82,814
2020	Sep	105	NA	$0.39	NA	102,265	NA	5,064	NA	$1,967	NA
2020	Oct	203	NA	$0.31	NA	80,004	NA	4,178	NA	$1,284	NA
2020	Nov	87	NA	$0.20	NA	89,206	NA	4,483	NA	$917	NA
2020	Dec	90	NA	$0.20	NA	100,921	NA	4,844	NA	$992	NA
2020		975	260	$0.60	$3.92	103,134	122,080	5,043	9,957	$3,050	$38,999
2021	Jan	28	NA	$0.08	NA	106,153	NA	4,847	NA	$380	NA
2021	Feb	32	NA	$0.16	NA	108,947	NA	4,974	NA	$815	NA
2021	Mar	24	NA	$0.17	NA	92,014	NA	4,327	NA	$732	NA
2021	Apr	129	NA	$0.21	NA	83,962	NA	3,983	NA	$846	NA
2021	May	68	11	$0.60	$1.91	99,007	105,454	4,661	9,514	$2,785	$18,147
2021	Jun	83	77	$0.41	$4.55	115,654	118,494	5,170	8,973	$2,124	$40,839
2021	Jul	115	46	$0.44	$1.41	122,396	129,739	5,460	7,842	$2,424	$11,095
2021	Aug	110	83	$0.35	$3.85	121,022	133,350	5,399	7,869	$1,877	$30,312
2021	Sep	107	40	$0.58	$3.45	104,852	105,046	4,776	9,117	$2,769	$31,492
2021	Oct	222	NA	$0.50	NA	87,526	NA	4,335	NA	$2,159	NA
2021	Nov	228	NA	$0.30	NA	89,025	NA	4,209	NA	$1,258	NA
2021	Dec	41	NA	$0.26	NA	100,378	NA	4,546	NA	$1,189	NA
2021		1,187	257	$0.39	$3.51	99,647	122,653	4,633	8,460	$1,791	$29,689

Table 10-34 shows total number of hours when a DASR market cleared at a price above $0 along with average load, cleared MW, additional MW under AFD, and total charges for the DASR market in January 2020 through December 2021.

Table 10-34 DASR market all hours of DASR market clearing price greater than $0: January 2020 through December 2021

Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load MW	PJM Cleared DASR MW	PJM Cleared Additional DASR MW	Credits
2020	Jan	3	$0.10	111,016	14,817	0	$1,462
2020	Feb	3	$0.10	109,218	15,961	0	$1,524
2020	Mar	1	$0.19	92,458	4,532	0	$861
2020	Apr	0	NA	NA	NA	NA	NA
2020	May	31	$0.29	96,413	146,052	0	$42,272
2020	Jun	156	$1.28	110,779	1,015,850	212,736	$1,298,963
2020	Jul	333	$3.20	123,379	2,753,429	850,906	$8,819,472
2020	Aug	223	$1.71	118,232	1,349,321	87,283	$2,312,941
2020	Sep	105	$0.39	102,265	531,772	0	$206,569
2020	Oct	203	$0.31	80,004	848,099	0	$260,746
2020	Nov	87	$0.20	89,206	390,026	0	$79,753
2020	Dec	90	$0.20	100,921	435,941	0	$89,283
2020	Total	1,235	$1.75	107,123	7,505,798	1,150,925	$13,113,848
2021	Jan	28	$0.08	106,153	135,710	0	$10,640
2021	Feb	32	$0.16	108,947	159,163	0	$26,076
2021	Mar	24	$0.17	92,014	103,839	0	$17,564
2021	Apr	129	$0.21	83,962	513,819	0	$109,108
2021	May	79	$0.92	99,905	421,593	53,470	$389,001
2021	Jun	160	$2.97	117,021	1,120,041	351,422	$3,320,941
2021	Jul	161	$0.80	124,494	988,574	97,972	$789,171
2021	Aug	193	$2.18	126,324	1,246,974	168,469	$2,722,344
2021	Sep	147	$1.78	104,905	875,744	150,928	$1,555,947
2021	Oct	222	$0.50	87,526	962,369	0	$479,311
2021	Nov	228	$0.30	89,025	959,656	0	$286,903
2021	Dec	41	$0.26	100,378	186,385	0	$48,735
2021	Total	1,444	$1.27	103,741	7,673,868	822,262	$9,755,740

When the DASR requirement is increased by PJM dispatch, the reserve requirement frequently cannot be met without redispatching online resources which significantly affects the price by creating an LOC. Adjusted Fixed Demand related increases in the DASR requirement (Table 10-34) in 2020 caused prices to increase.

Regulation Market

Regulation matches generation with very short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single real-time market.

Market Design

PJM's regulation market design is a result of Order No. 755.[78] The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types in a single market.

The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, with slower ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour.

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor (MBF) and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

The regulation market solution is intended to meet the regulation requirement with the least cost combination of RegA and RegD. When solving for the least cost combination of RegA and RegD MW to meet the regulation requirement, the regulation market will substitute RegD MW for RegA MW when RegD is cheaper. Performance adjusted RegA MW are used as the common unit of measure, called effective MW,

78 Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

of regulation service. All resource MW (RegA and RegD) are converted into effective MW. RegA MW are converted into effective MW by multiplying the RegA MW offered by their performance score. RegD MW are converted into effective MW by multiplying the RegD offered by their performance score and by the MBF. The regulation requirement is defined as the total effective MW required to provide a defined amount of area control error (ACE) control.

The regulation market converts performance adjusted RegD MW into effective MW using the MBF in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per marginal effective MW.

The marginal rate of technical substitution (MRTS) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying a defined regulation requirement at feasible combinations of RegA and RegD MW. While resources following RegA and RegD can both provide regulation service in PJM's Regulation Market, PJM's joint optimization is intended to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW using the RegD offer and the MBF associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to effective MW is equal to the MRTS associated with that RegA/RegD combination.

For example, a 1.0 MW RegD resource with a total offer price of $2 per MW with a MBF of 0.5 and a performance score of 100 percent would be calculated as offering 0.5 effective MW (0.5 MBF times 1.00 performance score times 1 MW). The total offer price would be $4 per effective MW ($2 per MW offer divided by the 0.5 effective MW).

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[79] Performance scores are reported on an hourly basis for each resource.

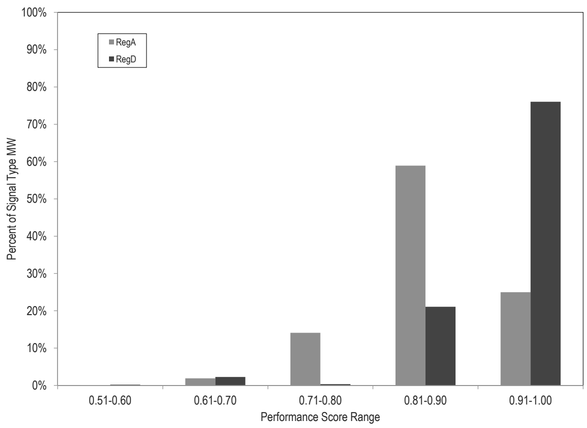
Table 10-35 and Figure 10-9 show the average performance score by resource type and the signal followed in 2021. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[80] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-9 shows, 76.0 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 25.0 percent of RegA resources had average performance scores within that range in 2021. In 2020, 82.2 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 33.2 percent of RegA resources had average performance scores within that range.

Table 10-35 Hourly average performance score by unit type: 2021

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CC	0.0%	0.0%	0.0%	0.0%	100.0%
	CT	0.0%	0.3%	5.4%	53.7%	40.5%
	Diesel	0.0%	0.0%	0.0%	15.2%	84.8%
	DSR	0.0%	0.0%	29.3%	56.7%	14.0%
	Hydro	0.0%	0.0%	0.1%	39.9%	60.0%
	Steam	0.1%	2.7%	19.7%	66.4%	11.1%
RegD	Battery	0.2%	2.4%	0.0%	18.5%	78.8%
	CC	-	-	-	-	-
	CT	0.0%	0.0%	7.7%	77.9%	14.4%
	Diesel	0.0%	0.0%	0.8%	80.3%	18.9%
	DSR	0.1%	0.0%	6.8%	63.2%	30.0%
	Hydro	0.0%	0.4%	0.0%	34.1%	65.6%
	Steam	-	-	-	-	-

79 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 43 (June 6, 2021).
80 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Figure 10-9 Hourly average performance score by regulation signal type: 2021



Each cleared resource in a class (RegA or RegD) is allocated a portion of the class signal (RegA or RegD). This portion of the class signal is based on the cleared regulation MW of the resource relative to the cleared MW for that class. This signal is called the Total Regulation Signal (TREG) for the resource. A resource with 10 MW of capability will be provided a TREG signal asking for a positive or negative regulation movement between negative and positive 10 MW around its regulation set point.

Resources are paid Regulation Market Clearing Price (RMCP) credits and lost opportunity cost credits, which are uplift payments. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference. PJM posts clearing prices for the regulation market (RMCCP, RMPCP and RMCP) in dollars per effective MW. The regulation market clearing price (RMCP in $/effective MW) for the hour is the simple average of the 12 five minute RMCPs within the hour. The RMCP is set in each five minute interval based on the marginal offer in each interval. The performance clearing price (RMPCP in $/effective MW) is based on the marginal performance offer (RMPCP) for the hour. The capability clearing price (RMCCP in $/effective MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour. This is done so the total of RMPCP plus RMCCP equals the total clearing price (RMCP) but the RMPCP is maximized.

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED) solving every 15 minutes; and the real-time security constrained economic dispatch market solution (RT SCED) solving approximately every five minutes. The market clearing price is determined by pricing software (LPC) that looks at the units cleared in the most recently approved RT SCED case, approximately 10 minutes ahead of the target solution time. The marginal prices assigned by the LPC to five minute intervals are averaged over the hour for an hourly regulation market clearing price.

Market Design Issues

PJM's current regulation market design is severely flawed and is not efficient or competitive. The market results do not represent the least cost solution for the defined level of regulation service.

In a well functioning market, every resource should be paid the same clearing price per unit produced. That is not true in the PJM Regulation Market. RegA and RegD resources are not paid the same clearing price in dollars per effective MW. RegD resources are being paid more than the market clearing price. This flaw in the market design has caused operational issues, has caused over investment in RegD resources.

If all MW of regulation were treated the same in both the clearing of the market and in settlements, many of the issues in the PJM Regulation Market would be resolved. However, the current PJM rules result in the payment to RegD resources being up to 1,000 times the correct price.

RegA and RegD have different physical capabilities. In order to permit RegA and RegD to compete in the single PJM Regulation Market, RegD must be translated into the same units as RegA. One MW of RegA is one effective MW. The translation is done using the marginal benefit factor (MBF). As more RegD is added to the market, the relative value of RegD declines, based on its actual performance attributes. For example, if the MBF is 0.001, a MW of RegD is worth 0.001 MW of RegA (or 1/1,000 of a MW of RegA). This is the same thing as saying that 1.0 MW of RegD is equal to 0.001 effective MW when the MBF is 0.001.

Almost all of the issues in PJM's Regulation Market are caused by the inconsistent application of the MBF.

Because the MBF is not included in settlements, when the MBF is less than 1.0, RegD resources are paid too much. When the MBF is less than 1.0, each MW of RegD is worth less than 1.0 MW of RegA. The market design buys the correct amount of RegD, but pays RegD as if the MBF were 1.0. In an extreme case, when the MBF is 0.001, RegD MW are paid 1,000 times too much. If the market clearing price is $1.00 per MW of RegA, RegD is paid $1,000 per effective MW. Resolution of this problem requires that PJM pay RegD for the same effective MW it provides in regulation, 0.001 MW.

To address the identified market flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the proposal finding it inconsistent with Order No. 755.

The MBF related issues with the regulation market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial solution to the RegD over procurement problem which was implemented on December 14, 2015. The interim solution was designed to reduce the relative value of RegD MW in all hours and to cap purchases of RegD MW during critical performance hours. But the interim solution did not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Additional changes were implemented on January 9, 2017. These modifications included changing the definition of off peak and on peak hours, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15 minute neutrality requirement of the RegD signal to a 30 minute neutrality requirement.

The January 9, 2017, design changes appear to have been intended to make RegD more valuable. That is not a reasonable design goal. The design goal should be to determine the least cost way to provide needed regulation. The RegA signal is now slower than it was previously, which may make RegA following resources less useful as ACE control. RegA is now explicitly used to support the conditional energy neutrality of RegD. The RegD signal is now the difference between ACE and RegA. RegA is required to offset RegD when RegD moves in the opposite direction of that required by ACE control in order to permit RegD to recharge. These changes in the signal design will allow PJM to accommodate more RegD in its market solutions. The new signal design is not making the most efficient use of RegA and RegD resources. The explicit reliance on RegA to offset issues with RegD is a significant conceptual change to the design that is inconsistent with the long term design goal for regulation. PJM increased the regulation requirement as part of these changes.

The January 9, 2017, design changes replaced off peak and on peak hours with nonramp and ramp hours with definitions that vary by season. The regulation requirement for ramp hours was increased from 700 MW to 800 MW (Table 10-36). These market changes still do not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Table 10-36 Seasonal regulation requirement definitions[81]

Season	Dates	Nonramp Hours	Ramp Hours
Winter	Dec 1 - Feb 28(29)	00:00 - 03:59 09:00 - 15:59	04:00 - 08:59 16:00 - 23:59
Spring	Mar 1 - May 31	00:00 - 04:59 08:00 - 16:59	05:00 - 07:59 17:00 - 23:59
Summer	Jun 1 - Aug 31	00:00 - 04:59 14:00 - 17:59	05:00 - 13:59 18:00 - 23:59
Fall	Sep 1 - Nov 30	00:00 - 04:59 08:00 - 16:59	05:00 - 07:59 17:00 - 23:59

Performance Scores

Performance scores, by class and unit, are not an indicator of how well resources contribute to ACE control. Performance scores are an indicator only of how well the resources follow their TREG signal. High performance scores with poor signal design are not a meaningful measure of performance. For example, if ACE indicates the need for more regulation but RegD resources have provided all their available energy, the RegD regulation signal will be in the opposite direction of what is needed to control ACE. So, despite moving in the wrong direction for ACE control, RegD resources would get a good performance score for following the RegD signal and will be paid for moving in the wrong direction.

81 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

The RegD signal prior to January 9, 2017, is an example of a signal that resulted in high performance scores, but due to 15 minute energy neutrality built into the signal, ran counter to ACE control at times. Energy neutrality means that energy produced equals energy used within a defined timeframe. With 15 minute energy neutrality, if a battery were following the regulation signal to provide MWh for 7.5 minutes, it would have to consume the same amount of MWh for the next 7.5 minutes. When neutrality correction of the RegD signal is triggered, it overrides ACE control in favor of achieving zero net energy over the 15 minute period. When this occurs, the RegD signal runs counter to the control of ACE and hurts rather than helps ACE. In that situation, the control of ACE, which must also offset the negative impacts of RegD, depends entirely on RegA resources following the RegA signal. High performance scores under the signal design prior to January 9, 2017, was not an indication of good ACE control.

The January 9, 2017, design changes did not address the fundamental issues with the definition of performance or the nature of payments for performance in the regulation market design. The regulation signal should not be designed to favor a particular technology. The signal should be designed to result in the lowest cost of regulation to the market. Only with a performance score based on full substitutability among resource types should payments be based on following the signal. The MRTS must be redesigned to reflect the actual capabilities of technologies to provide regulation. The PJM regulation market design remains fundamentally flawed.

In addition, the absence of a performance penalty, imposed as a reduction in performance score and/or as a forfeiture of revenues, for deselection initiated by the resource owner within the hour, creates a possible gaming opportunity for resources which may overstate their capability to follow the regulation signal. The MMU recommends that there be a penalty enforced as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming.

Battery Settlement

The change from 15 to 30 minute signal neutrality, implemented in the January 9, 2017, design changes, resulted in the reduction of performance scores for short duration batteries. In April 2017 several participants filed a complaint against PJM, asserting that these changes discriminated against their battery units.[82] The MMU objected to the complaints. Despite the unsupported assertions in the complaint, PJM settled with the participants that was approved by FERC on April 7, 2020.[83] Table 10-37 shows the battery units that are part of the settlement. Starting July 1, 2020, the affected battery units began receiving compensation based on the greater of their current performance score, or their rolling average actual hourly performance score for the last 100 hours the resource operated prior to the January 9, 2017, implementation of the 30-minute conditional neutrality. The additional regulation credits received as a result of the settlement are shown in Table 10-38.

Table 10-37 Batteries in settlement

Parent Company	Unit	MW
The AES Corporation	Laurel Mountain	32.0
	Warrior Run	10.0
Energy Capital Partners, LLC	Hazel	20.0
Galt Power, Inc.	Trent	4.0
	McHenry	20.0
	Beckjord 1	2.0
	Beckjord 2	2.0
Invenergy, LLC	Beech Ridge	31.5
	Grand Ridge 6	4.5
	Grand Ridge 7	31.5
NextEra Energy, Inc.	Lee Dekalb	20.0
	Garrett	10.4
	Meyersdale	18.0
	Mantua Creek	2.0
Renewable Energy Systems Holdings, LTD	Joliet	20.0
	West Chicago	20.0
Sumitomo Corporation	Willey	6.0

Table 10-38 Excess regulation credits received by settlement batteries: January through December, 2021

Month	Excess Regulation Credit ($)
Jan	$40,752
Feb	$82,768
Mar	$76,248
Apr	$61,786
May	$65,797
Jun	$60,896
Jul	$76,253
Aug	$136,365
Sep	$112,929
Oct	$156,829
Nov	$213,585
Dec	$118,995
Total	$1,203,204

82 See FERC Docket Nos. EL17-64-000 and EL17-65-000.
83 See 170 FERC ¶ 61,258 (2020).

In addition to paying uneconomic regulation credits based on inflated performance scores, the settlement also requires that the affected battery units be cleared in the regulation market regardless of whether their offer was economic. As long as the settlement batteries are offered as either self scheduled with a zero offer, or as a zero priced offer, they must be cleared despite the fact that these units would not necessarily have cleared based on economics.[84] In order to comply with this condition, PJM clears additional MW beyond what is needed for the regulation requirement in cases where the settlement battery units did not clear but met the offer rules of the settlement. This results in excess charges to customers for regulation service. Table 10-39 shows the impact of clearing additional MW beyond what is needed for the regulation requirement, as a result of the battery settlement. Other changes in market dynamics starting in the third quarter of 2021 reduced the impact of this settlement rule because most of the settlement units clear based on economics. In 2021, the battery settlement resulted in customers paying $359,644 more than needed to compensate the additional MW from settlement batteries that would not have otherwise cleared. As a result of the battery settlement, PJM customers in 2021 over paid for regulation by $1.6M (the sum of Table 10-38 and Table 10-39).

Table 10-39 Excess payments and MW cleared due to battery settlement: January through December, 2021

Battery Settlement Impact		
Month	Regulation Credits	Additional Cleared Regulation MW
Jan	$49,387	3,149.4
Feb	$24,776	1,727.7
Mar	$37,648	3,192.6
Apr	$78,650	4,872.3
May	$117,329	7,718.7
Jun	$2,092	147.4
Jul	$1,856	26.3
Aug	$205	8.5
Sep	$955	26.9
Oct	$33,819	1,046.2
Nov	$12,888	238.7
Dec	$39	4.9
Total	$359,644	22,159.4

Regulation Signal

As with any signal design for substitutable resources, the MBF function should be determined by the ability of RegA and RegD resources to follow their signals, including conditions under which neutrality cannot be maintained by RegD resources. The ability of energy limited RegD to provide ACE control depends on the availability of excess RegA capability to support RegD under the conditional neutrality design. When RegD resources are largely energy limited resources, a correctly calculated MBF would exhibit a rapid decrease in the MBF value for every MW of RegD added. The result is that only a small amount of energy limited RegD is economic. The current and proposed signals and corresponding MBF functions do not reflect these principles or the actual substitutability of resource types.

Marginal Benefit Factor Issues

The MBF function, as implemented in the PJM Regulation Market, is not equal to the MRTS between RegA and RegD. The MBF is not consistently applied throughout the market design, from optimization to settlement, and market clearing does not confirm that the resulting combinations of RegA and RegD are realistic and can meet the defined regulation demand. The calculation of total regulation cleared using the MBF is incorrect.[85]

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours, has provided a consistently inefficient market signal to participants regarding the value of RegD in every hour, and has overpaid for RegD. This over procurement has degraded the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

PJM and the MMU filed a joint proposal with FERC on October 17, 2017, to address issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market, but the proposal was rejected by FERC.[86]

Marginal Benefit Factor Not Correctly Defined

The MBF used in the PJM Regulation Market prior to the December 14, 2015, changes did not accurately reflect the MRTS between RegA and RegD resources under the old market design, and it does not accurately reflect the MRTS between RegA and RegD resources under

84 See *id.* at P 17.

85 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.

86 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

the current design. The MBF function is incorrectly defined and improperly implemented in the current PJM Regulation Market.

The MBF should be the marginal rate of technical substitution between RegA and RegD MW at different, feasible combinations of RegA and RegD that can be used to provide a defined level of regulation service. The objective of the market design is to find, given the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the MBF function is incorrectly defined, or improperly implemented in the market clearing and settlement, the resulting combinations of RegA and RegD will not represent the least cost solution and may not be a feasible way to reach the target level of regulation.

The MBF is not included in PJM's settlement process. This is a design flaw that results in incorrect payments for regulation. The issue results from two FERC orders. From October 1, 2012, through October 31, 2013, PJM implemented a FERC order that required the MBF to be fixed at 1.0 for settlement calculations only. On October 2, 2013, FERC directed PJM to eliminate the use of the MBF entirely from settlement calculations of the capability and performance credits and replace it with the RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective retroactively to October 1, 2012.[87] That rule continues in effect. The result of the current FERC order is that the MBF is used in market clearing to determine the relative value of an additional MW of RegD, but the MBF is not used in the settlement for RegD.

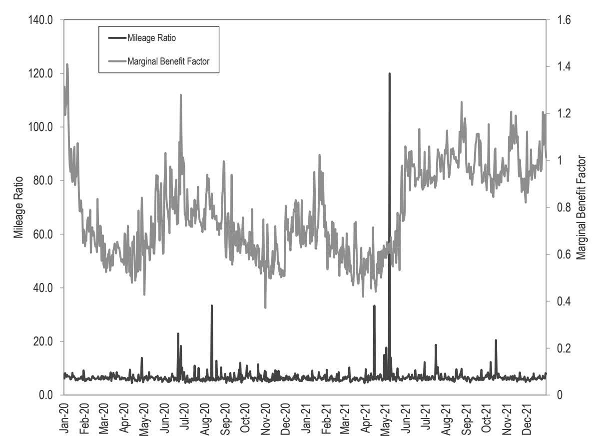
If the MBF were consistently applied, every resource would receive the same clearing price per marginal effective MW. But the MBF is not consistently applied and resources do not receive the same clearing price per marginal effective MW.

The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the mileage required of RegD resources and changed the energy neutrality component of the signal from a strict 15 minute neutrality to a conditional 30 minute neutrality. The changes in signal design increased the mileage ratio (the ratio of RegD mileage to RegA mileage). In addition, to adapt to the 30 minute neutrality requirement, some RegD resources decreased their offered capability to maintain their performance.

Figure 10-10 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio increased from 6.55 in 2020, to 6.95 in 2021 (an increase of 6.2 percent). The average MBF increased from 0.71 in 2020, to 0.84 in 2021 (an increase of 17.3 percent). The high mileage ratios are the result of the mechanics of the mileage ratio calculation. Extreme mileage ratios result when the RegA signal is fixed at a single value (pegged) to control ACE and the RegD signal is not. If RegA is held at a constant MW output, mileage is zero for RegA. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio is very large.

These results are an example of why it is not appropriate to use the mileage ratio, rather than the MBF, to measure the relative value of RegA and RegD resources. In these events, RegA resources are providing ACE control by providing a fixed level of MW output which means zero mileage, while RegD resources alternate between helping and hurting ACE control, both of which result in positive mileage.

Figure 10-10 Daily average MBF and mileage ratio: January 2020 through December 2021



87 145 FERC ¶ 61,011 (2013).

The increase in the average mileage ratio caused by the signal design changes introduced on January 9, 2017, caused a large increase in payments to RegD resources on a performance adjusted MW basis.

Table 10-40 shows RegD resource payments on a performance adjusted actual MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2020, through December 31, 2021. The average regulation market clearing price in 2021 was $12.45 higher than in 2020 (See Table 10-40). Coupled with the average MBFs of less than 1.0, RegD continued to be overpaid compared to RegA on a performance adjusted actual MW basis. In 2021, RegD resources earned 20.7 percent more per performance adjusted actual MW than RegA resources (23.2 percent in 2020) due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-40 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2020 through December 2021

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent RegD Overpayment ($/Performance Adjusted MW)
2020	Jan	$16.51	$13.05	26.5%
	Feb	$11.83	$9.57	23.6%
	Mar	$11.06	$8.60	28.6%
	Apr	$14.29	$11.45	24.8%
	May	$14.72	$12.46	18.2%
	Jun	$15.09	$11.85	27.3%
	Jul	$18.02	$15.63	15.3%
	Aug	$18.11	$14.83	22.2%
	Sep	$12.68	$10.33	22.7%
	Oct	$21.82	$17.31	26.0%
	Nov	$19.45	$15.25	27.5%
	Dec	$18.18	$15.34	18.6%
Yearly		$16.01	$13.00	23.2%
2021	Jan	$14.29	$11.43	25.1%
	Feb	$23.87	$19.90	19.9%
	Mar	$20.81	$17.93	16.0%
	Apr	$20.86	$16.73	24.6%
	May	$20.22	$16.42	23.2%
	Jun	$23.01	$18.40	25.1%
	Jul	$24.09	$19.33	24.6%
	Aug	$37.86	$31.77	19.2%
	Sep	$34.62	$28.59	21.1%
	Oct	$46.15	$38.91	18.6%
	Nov	$61.59	$52.92	16.4%
	Dec	$33.56	$26.85	25.0%
Yearly		$30.08	$24.93	20.7%

The current settlement process does not result in paying RegA and RegD resources the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the MBF is not used in settlements. Instead of being paid based on the MBF, (RMCCP + RMPCP)*MBF, RegD resources are paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis, unless offset by a low mileage ratio. The average MBF was less than 1.0 in 2021 (0.84).

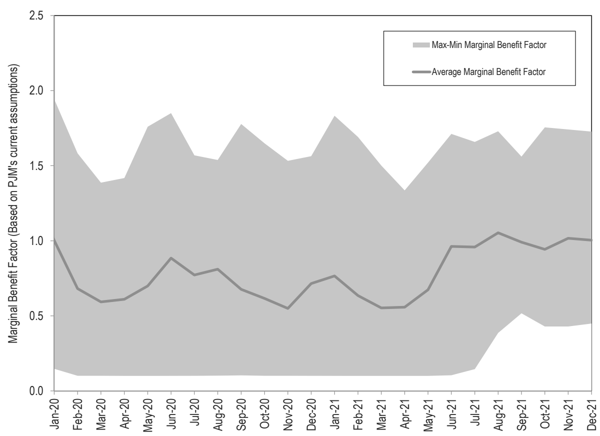
The effect of using the mileage ratio instead of the MBF for purposes of settlement is illustrated in Table 10-41. Table 10-41 shows how much RegD resources are currently being paid, adjusted to a per effective MW basis, on average, in 2020 and 2021 under the current rules, compared to how much RegD resources should have been paid if they were actually paid for effective MW. Using the MBF consistently throughout the PJM regulation market would result in RegA and RegD resources being paid exactly the same on a per effective MW basis. However, the PJM regulation market only uses the MBF in the market clearing and setting of price on a dollar per effective MW basis, it does not use the MBF to convert RegD MW into effective MW for purposes of settlement. Because the MBF is not used to convert RegD MW into effective MW for purposes settlement, RegD resources are paid the dollar per effective MW price, but this is paid for performance adjusted MW, not for effective MW. This causes the MW value of RegD resources to be inflated in settlement when the MBF is less than one. In 2021, the MBF averaged 0.84, while the average daily mileage ratio was 6.95, resulting in RegD resources being paid $8.9 million more than they would have been paid on an effective MW basis if the MBF were correctly implemented. In 2020, the MBF averaged 0.72, and the average mileage ratio was 6.55, resulting in RegD resources being paid $9.3 million more than they would have been paid if the MBF were correctly implemented.

Table 10-41 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2020 through December 2021[88]

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment ($/Effective MW)	Total RegD Overpayment ($)
2020	Jan	$19.61	$13.05	$13.05	50.3%	$318,560
	Feb	$25.79	$9.57	$9.57	169.5%	$505,037
	Mar	$29.47	$8.60	$8.60	242.6%	$665,219
	Apr	$38.85	$11.45	$11.45	239.4%	$745,528
	May	$37.37	$12.46	$12.46	199.9%	$746,137
	Jun	$25.00	$11.85	$11.85	111.0%	$548,730
	Jul	$34.99	$15.63	$15.63	123.9%	$657,628
	Aug	$31.78	$14.83	$14.83	114.4%	$753,199
	Sep	$28.51	$10.33	$10.33	175.9%	$661,906
	Oct	$69.18	$17.31	$17.31	299.6%	$1,534,621
	Nov	$63.11	$15.25	$15.25	313.8%	$1,319,529
	Dec	$43.39	$15.34	$15.34	182.9%	$886,873
Yearly		$37.30	$13.00	$13.00	186.9%	$9,342,966
2021	Jan	$30.47	$11.43	$11.43	166.6%	$558,397
	Feb	$88.91	$19.90	$19.90	346.7%	$1,310,283
	Mar	$61.03	$17.93	$17.93	240.4%	$1,277,850
	Apr	$65.99	$16.73	$16.73	294.3%	$1,492,094
	May	$39.55	$16.42	$16.42	140.9%	$1,081,445
	Jun	$26.57	$18.40	$18.40	44.4%	$457,543
	Jul	$27.36	$19.33	$19.33	41.5%	$513,186
	Aug	$38.23	$31.77	$31.77	20.4%	$288,112
	Sep	$35.63	$28.59	$28.59	24.6%	$410,694
	Oct	$51.13	$38.91	$38.91	31.4%	$688,515
	Nov	$63.20	$52.92	$52.92	19.4%	$377,458
	Dec	$33.94	$26.85	$26.85	26.4%	$399,675
Yearly		$46.48	$24.93	$24.93	86.4%	$8,855,253

Figure 10-11 shows, the monthly maximum, minimum and average MBF, for January 2020 through December 2021. The average daily MBF in 2021 was 0.84. The average daily MBF in 2020 was 0.72. The bottom of the MBF range results from PJM's administratively defined MBF minimum threshold of 0.1. The increase in the minimum and average MBF starting in the third quarter of 2021 was the result of a reduction in RegD offered MW and cleared MW (See Figure 10-16).

Figure 10-11 Maximum, minimum, and average PJM calculated MBF by month: January 2020 through December 2021



88 There was an error in previously reported versions of this table. The total RegD overpayment column was overstated. The correct values are included here.

The MMU recommends that the regulation market be modified to incorporate a consistent and correct application of the MBF throughout the optimization, assignment and settlement process.[89]

The overpayment of RegD has resulted in offers from RegD resources that are almost all at an effective cost of $0.00 ($0.00 offers plus self scheduled offers). RegD MW providers are ensured that such offers will clear and will be paid a price determined by the offers of RegA resources. This is evidence of the impact of the flaws in the clearing engine and the overpayment of RegD resources on the offer behavior of RegD resources.

Table 10-42 shows, by month, cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for January 2020 through December 2021. In 2021, an average of 98.6 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first 2020, an average of 99.7 percent of all cleared RegD MW had an effective cost of $0.00. In 2021, an average of 71.6 percent of all RegD offers were self scheduled, compared to an average of 76.2 percent of all RegD offers in 2020.

The high percentage of self scheduled offers is a result of the incentives created by the flaws in the regulation market. Because self scheduled offers are price takers, they are cleared along with the zero cost offers in the market clearing engine. However, unlike zero cost offers, self scheduled offers do not risk having an LOC added to their offer during the market clearing process, ensuring that self scheduled offers have a zero cost during market clearing. Given the increasing saturation of the regulation market with RegD MW, specifically demand response and battery units which do not receive LOC, market participants eligible for LOC that offer at zero instead of self scheduling, run the risk of an LOC added to their offer, and thus not clearing the market.

The average monthly RegD cleared in the market decreased 10.0 MW (5.2 percent), from 193.5 MW in 2020 to 183.5 MW in 2021. The average monthly RegD cleared with an effective cost of zero decreased 11.9 MW (6.2 percent), from 193.0 MW in 2020 to 181.1 MW in 2021. Self scheduled RegD cleared MW decreased 15.5 MW (10.5 percent), from 147.4 MW in 2020 to 131.9 MW in 2021. Average cleared RegD MW with a zero cost offer increased 3.6 MW (7.9 percent), from 45.6 MW in 2020 to 49.2 MW in 2021. The decrease in the average monthly RegD cleared resulted in the increase of the average monthly MBF seen in Figure 10-11.

89 See "Regulation Market Review," Operating Committee (May 5, 2015) <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

Table 10-42 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2020 through December 2021

		Average Performance Adjusted Cleared RegD MW						
Year	Month	$0.00 Offer	$0.00 Offer Percent of Total	Self Scheduled	Self Scheduled Percentage of Total	Total Effective Cost of Zero	Effective Cost of Zero Percentage of Total	Total
2020	Jan	32.1	18.8%	137.2	80.5%	169.2	99.4%	170.3
	Feb	48.8	24.6%	149.6	75.4%	198.5	100.0%	198.5
	Mar	48.0	24.4%	148.1	75.5%	196.1	100.0%	196.1
	Apr	47.1	24.0%	149.3	75.9%	196.4	99.9%	196.7
	May	43.2	22.6%	147.6	77.3%	190.8	99.9%	191.0
	Jun	47.7	24.7%	143.8	74.5%	191.4	99.2%	192.9
	Jul	47.9	24.0%	151.0	75.7%	199.0	99.8%	199.4
	Aug	48.2	24.5%	147.5	74.9%	195.6	99.3%	196.9
	Sep	40.7	21.3%	149.7	78.4%	190.4	99.7%	191.0
	Oct	46.2	23.7%	148.7	76.1%	194.9	99.8%	195.3
	Nov	50.3	25.3%	148.5	74.7%	198.8	100.0%	198.9
	Dec	47.2	24.1%	147.9	75.7%	195.1	99.8%	195.4
Yearly		45.6	23.6%	147.4	76.2%	193.0	99.7%	193.5
2021	Jan	49.6	26.1%	139.9	73.7%	189.6	99.9%	189.8
	Feb	52.4	25.6%	152.3	74.4%	204.7	100.0%	204.7
	Mar	47.2	23.3%	155.4	76.7%	202.6	100.0%	202.6
	Apr	48.6	24.0%	154.0	76.0%	202.7	100.0%	202.7
	May	47.5	24.8%	143.8	75.0%	191.3	99.9%	191.6
	Jun	45.8	25.2%	133.3	73.4%	179.2	98.6%	181.7
	Jul	48.4	26.4%	130.7	71.4%	179.1	97.8%	183.1
	Aug	49.9	28.4%	120.8	68.6%	170.8	97.0%	176.0
	Sep	50.8	30.6%	111.1	67.1%	161.8	97.7%	165.6
	Oct	50.6	30.2%	114.6	68.3%	165.3	98.5%	167.7
	Nov	50.2	30.6%	109.0	66.5%	159.2	97.1%	164.0
	Dec	49.4	28.6%	118.0	68.2%	167.5	96.8%	173.0
Yearly		49.2	26.8%	131.8	71.9%	181.0	98.7%	183.4

Incorrect MBF and total effective MW when clearing units with dual product offers

Under PJM market rules, regulation units that have the capability to provide both RegA and RegD MW are permitted to submit an offer for both signal types in the same market hour. While the objective of the PJM market design is to find the least cost combination of RegA and RegD resources to provide the required level of regulation service, the method of clearing the regulation market for an hour in which one or more units has a dual offer is incorrect and leads to solutions that are not the most economic.

In order for the clearing engine to provide the correct economic solution when the pool of available resources contains one or more units with dual offers, the calculation would have to be performed iteratively to determine which of the dual offers would provide the least cost solution. But this is not how PJM clears the regulation market when there are dual offer units. PJM rank orders the regulation supply curve by potential effective cost assuming the dual offer resources are available as both RegA and RegD resources simultaneously, and assigns every RegD resource, including dual offer resources, a unit specific benefit factor.

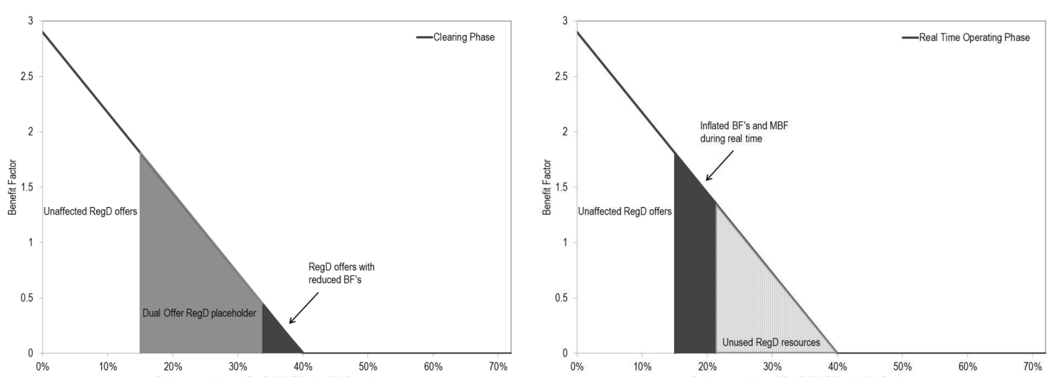
Each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. But PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

During the clearing phase, the MBF of RegD resources is a function of the RegD MW that clear. The MBF for all RegD resources declines as more RegD resources are cleared. Based on this relationship, in the case where a dual offer unit is assigned to be a RegA resource rather than a RegD resource, the MBF of remaining RegD resources in the supply curve should increase. The placeholder RegD MW from the dual offer should be removed, the cleared MW from below the placeholder should be shifted up the supply/MBF curve, and additional RegD MW offers that were pushed below an MBF of zero and initially not included, should be considered. But PJM does not recalculate the MBF values for the remaining RegD resources when determining the cleared effective MW needed to satisfy the regulation requirement during the clearing phase. The result is that the MBF in the clearing phase is incorrectly low, and the actual amount of effective MW procured is higher.

After meeting the target effective MW to satisfy the regulation requirement for that hour through the clearing process, the unit specific benefit factors of those displaced units are recalculated in the real-time operating phase and increased based on their actual contribution. The effective MW contributions of those originally displaced units are correctly calculated in the operating phase, but because the supply for that hour has already been set based on their incorrect effective MW, the solution includes more effective MW than calculated in the clearing phase. As a result, the market solution includes more than the target level of effective MW in the actual operating hour.

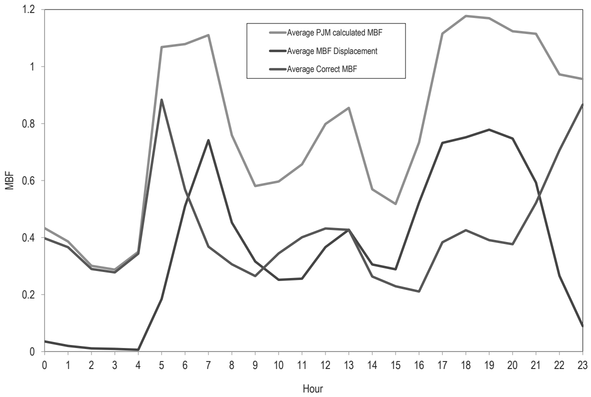
The issue is illustrated in Figure 10-12. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the curve in the clearing phase. The effective MW of the cleared RegD resources with higher effective costs are represented by the blue triangle in the clearing phase. Not shown are additional RegD MW with higher effective costs that were assigned an MBF of 0 and not cleared. The 150 MW dual offer unit is chosen to operate as a RegA resource in the operational hour. As a result, the cleared supply for RegA in the clearing phase is the same RegA supply realized in the real time operating phase. But that is not the case for the RegD supply. Since the supply curve and unit specific benefit factors of RegD MW are not recalculated in the clearing phase after the 150 MW RegD offer is removed, the amount of effective MW realized in the real-time operating phase is inconsistent with the clearing phase. Because the RegD portion of the 150 MW dual offer unit was not chosen to be RegD MW, the RegD resources represented by the blue triangle in the clearing phase will contribute more effective MW (the blue area in the real-time solution phase) in the real-time solution phase than was assumed in the clearing phase because the MBF in the clearing phase was too low. Since the blue area under the curve in the real-time solution phase is greater than the blue area in the clearing phase and the amount of RegA remains the same between the clearing phase and real-time operating phase, the market will have cleared too many effective MW relative to the effective MW requirement. The MBF in the operating phase is higher than if the clearing had been solved correctly.

Figure 10-12 Clearing phase BF/effective MW reduction, real-time BF/effective MW inflation, and exclusion of available RegD resources



In 2021, all hours had at least one unit with a dual offer. In 2021, 37.6 percent of all hours had at least one dual offer unit that was chosen to run as RegA, resulting in an average MBF increase of 0.48 in the operating phase. If the market had been cleared correctly, the correct average MBF would have been significantly lower in real time (operating phase), because additional RegD offers with lower benefit factors that were initially excluded, would have been included after the removal of the dual offer placeholder, reducing the MBF. Figure 10-13 illustrates the PJM calculated average MBF in real time (operating phase), the average MBF displacement due to dual offers clearing as RegA, and what the correct average MBF would have been in each hour of the day for 2021 if the clearing solution were solved correctly.

Figure 10-13 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: 2021



Absent the ability to correctly clear dual offers, the MMU recommends that the ability of resources to submit dual offers be removed. Under this revision to the rules, resources could offer as either RegA or RegD in a given hour, but not both within the same market hour.

Price Spikes

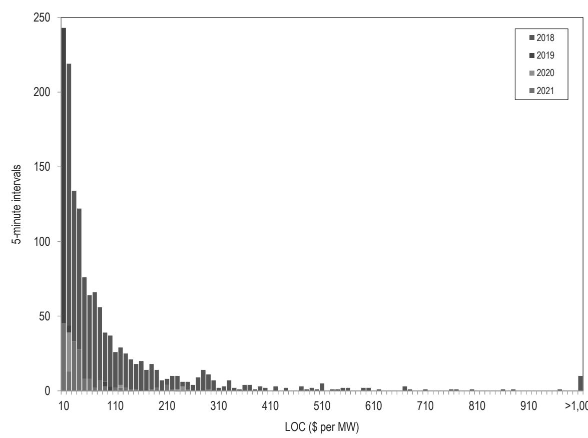
Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate of the adjusted LOC offer component, hour ahead projections of LMPs are used. Units are then cleared based on the sum of each of their hour ahead adjusted offer components. The actual LOC is used to determine the final, actual interval specific all in offer of RegD resources.

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit is less than one (e.g. the marginal unit is a RegD unit), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) and the realized offer price of the resource in the actual market result. This will cause a significant price spike in the regulation market. In cases where the MBF of the marginal resource is very low, such as 0.001, the price spikes can be very significant for a small change between expected and actual LOC. In January 2019, FERC approved PJM's proposal to create a 0.1 floor for the MBF to reduce the occurrence of these price spikes.[90] This change reduced the amount and frequency of the price spikes, but it was not designed to eliminate them and it did not eliminate them.

Figure 10-14 shows the LOC in each five minute interval in which the marginal unit had a unit specific benefit factor less than one (e.g. a RegD unit) and the LOC was greater than zero in 2018, 2019, 2020, and 2021.

Figure 10-14 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2018 through December 2021



90 See 166 FERC ¶ 61,040 (2019).

For a RegD resource to clear the regulation market with an MBF of 0.001, the resource's offer, in dollars per marginal effective MW, must be less than or equal to competing offers from RegA MW. A RegD offer of 1 MW with an MBF of 0.001 and a price of $1 per MW, would provide 0.001 effective MW at a price of $1,000 per effective MW. So long as RegA MW are available for less than $1,000 per effective MW, this resource will not clear. The only way for RegD MW to clear to the point where the MBF of the last MW is 0.001, is if the offer price of the relevant resources that clear, including estimated LOC, is $0.00. But, if the same resource(s) has a positive LOC within the hour, based on real-time changes in LMP, the zero priced offer is adjusted to reflect the positive LOC, resulting in an extremely high offer and clearing price for regulation.

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. But, due to the current market design's failure to use the MBF in settlement, RegD is not paid on a dollar per effective MW basis. This disconnect between the process of setting price and the process of paying resources is the primary source of the market failure in PJM's Regulation Market and the cause of the observed price spikes in the regulation market. In the example, the 0.001 MW from the RegD resource should be paid $1,000 times 0.001 MW or $1.00. But the current rules would pay the RegD resource $1,000 times 1.0 MW or $1,000. If the market clearing and the settlements rules were consistent, the incentive for this behavior would be eliminated. The current rules provide a strong incentive for this behavior.

The prices spikes observed in PJM's Regulation Market are a symptom of a market failure in PJM's Regulation Market caused by an inconsistent application of the MBF between market clearing and market settlement. Due to the inconsistent application of the MBF, the current market results are not consistent with a competitive market outcome. In any market, resources should be paid the marginal clearing price for their marginal contribution. In the regulation market, all resources should be paid the marginal clearing price per effective MW and all resources in the regulation market should be paid for each of their effective MW. PJM's Regulation Market does not do this. PJM's market applies the MBF in determining the relative and total value of RegD MW in the market solution for purposes of market clearing and price, but does not apply the same logic in determining the payment of RegD for purposes of settlement. As a result, market prices do not align with payment for contributions to regulation service in market settlements.

The inconsistent application of the MBF in PJM's regulation market design is generating perverse incentives and perverse market results. The price spikes are a symptom of the problem, not the problem itself.

Uplift Calculation Issues

Regulation uplift is calculated by comparing a resource's regulation offer price plus its regulation lost opportunity cost (including shoulder LOC if applicable) adjusted by the performance score, to the clearing price credits the unit received.[91] If the sum of the resources offer plus LOC is greater than the amount of clearing price credits received, additional uplift credits are given equal to the difference.

The calculation of regulation uplift during settlements for coal and natural gas units is incorrect, and results in the overpayment of uplift.[92] In order to determine the amount of regulation uplift, the difference between the MW output of the unit while it was providing regulation is compared to the desired MW output of the unit if it had not provided regulation. The desired amount of MW output at LMP used in the calculation of regulation uplift during settlements is determined based on a unit's energy offer and the LMP during the interval being evaluated. But this desired MW does not account for the ability of a unit to actually produce the desired output because it does not take into account the physical limitations of the unit's ability to ramp. This results in the overpayment of uplift by paying for MW that the unit could not have produced given their energy market output at the beginning of the interval and their ramp rate.

91 The clearing price for each interval is set by the marginal unit's total offer (capability and performance offers plus LOC), adjusted by the marginal unit's performance score, and does not include any shoulder LOC.

92 Hydro units operate on a schedule rather than an energy bid, therefore a different equation is used to calculate their regulation LOC and uplift. The issue discussed does not effect that calculation. Also, demand response and battery units do not receive uplift.

Table 10-43 shows the amount of uplift overpayment by fuel type for 2021. The overpayments are calculated using a desired MW level that can be achieved based on the units' ramp rates. In 2021, overpayments totaled $11.0 million. Coal units received 37.6 percent of the overpayment while providing 7.1 percent of settled regulation MW.

Table 10-43 Amount of LOC overpayment: January through December, 2021

	Uplift overpayment		
Month	Coal	Natural Gas	Total
Jan	$193,493	$158,574	$352,066
Feb	$192,078	$317,746	$509,824
Mar	$264,985	$429,131	$694,115
Apr	$193,678	$214,241	$407,919
May	$467,981	$178,919	$646,900
Jun	$565,172	$233,445	$798,618
Jul	$162,148	$180,590	$342,738
Aug	$143,573	$361,511	$505,084
Sep	$218,765	$528,205	$746,970
Oct	$160,570	$772,042	$932,612
Nov	$1,135,649	$2,485,585	$3,621,234
Dec	$444,082	$1,015,060	$1,459,142
Total	$4,142,174	$6,875,047	$11,017,221

Market Structure

Supply

Table 10-44 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in 2021.[93] Actual MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and by the resource specific benefit factor to get effective MW. A resource can choose to follow either signal. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the offers from units that are designated as available for the day. These are daily offers that can be modified on an hourly basis up to 65 minutes before the hour.[94] Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

In 2021, the average hourly offered supply of regulation for nonramp hours was 740.8 actual MW (744.9 effective MW). This was an increase of 19.9 actual MW (an increase of 23.7 effective MW) from 2020, when the average hourly offered supply of regulation was 720.9 actual MW (721.3 effective MW). In 2021, the average hourly offered supply of regulation for ramp hours was 1,066.4 actual MW (1,094.9 effective MW). This was an increase of 49.0 actual MW (an increase of 36.0 effective MW) from 2020, when the average hourly offered supply of regulation was 1,017.4 actual MW (1,058.9 effective MW).

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.51 in 2021 (1.45 in 2020). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 1.54 in 2021 (1.47 in 2020).

93 Unless otherwise noted, analysis provided in this section uses PJM market data based on PJM's internal calculations of effective MW values, based on PJM's currently incorrect MBF curve. The MMU is working with PJM to correct the MBF curve.

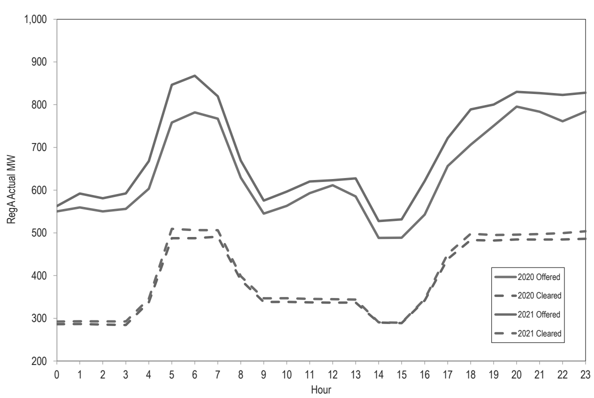
94 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 116 (September 1, 2021).

Table 10-44 Hourly average actual and effective MW offered and cleared: 2021[95]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,066.4	1,055.4	10.9	829.6	236.8
	Nonramp	740.8	733.3	7.5	548.5	192.2
Effective Offered MW	Ramp	1,094.9	1,080.9	14.0	715.0	379.9
	Nonramp	744.9	737.6	7.3	470.6	274.4
Actual Cleared MW	Ramp	706.9	696.0	10.9	502.5	204.4
	Nonramp	481.6	474.3	7.4	291.4	190.2
Effective Cleared MW	Ramp	800.0	786.0	14.0	435.2	364.8
	Nonramp	525.2	518.0	7.2	251.7	273.5

The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-15. The average hourly offered MW from RegA resources during ramp hours for 2021 was 829.6 actual MW, an increase of 7.8 percent from 2020 (769.7 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for 2021 was 548.5 actual MW, an increase of 6.6 percent from 2020 (514.5 actual MW). The average hourly cleared MW from RegA resources during ramp hours for 2021 was 502.5 actual MW, an increase of 3.2 percent from 2020 (486.9 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for 2021 was 291.4 actual MW, an increase of 1.5 percent from 2020 (287.0 actual MW).

Figure 10-15 Average hourly RegA actual MW offered and cleared: January through December, 2020 through 2021[96]



The average hourly offered MW from RegD resources during ramp hours for 2021 was 236.8 actual MW, a decrease of 4.4 percent from 2020 (247.7 actual MW). (Figure 10-16) The average hourly offered MW from RegD resources during nonramp hours for 2021 was 192.2 actual MW, a decrease of 6.9 percent from 2020 (206.4 actual MW) (Figure 10-16). The average hourly cleared MW from RegD resources during ramp hours for 2021 was 204.4 actual MW, a decrease of 5.3 percent from 2020 (216.0 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for 2021 was 190.2 actual MW, a decrease of 7.2 percent from 2020 (204.9 actual MW).

Figure 10-16 Average hourly RegD actual MW offered and cleared: January through December, 2020 through 2021[97]

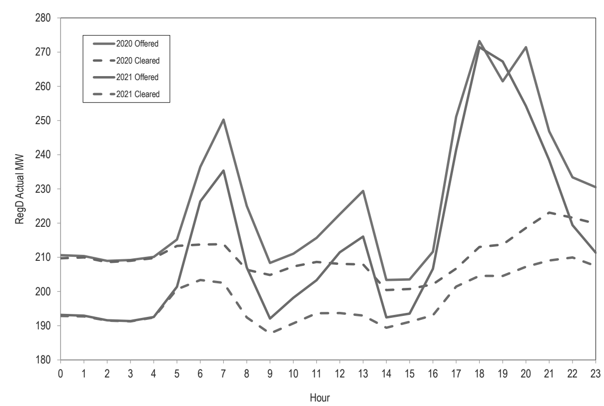


Table 10-46 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-46 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW decreased 0.2 percent from 4,625,428.8 MW in 2020 to 4,616,116.0 MW in 2021. The average proportion of regulation provided by hydro and natural gas units increased by 0.9 percent from 2020 to 2021.

95 PJM operations treats some nonramp hours as ramp hours, with a regulation requirement of 800 MW rather than 525 MW. All ramp/nonramp analysis performed is based on the requirement used in each hour rather than the definitions given in Table 10-2. A ramp hour occurring during what is normally a nonramp period is treated as a ramp hour.

96 Offered MW includes MW from units that are dual offering as both RegA and RegD.

97 Offered MW includes MW from units that are dual offering as both RegA and RegD.

Battery units had the largest decrease in average proportion of regulation provided, decreasing 1.3 percent, from 34.6 percent in 2020, to 33.3 percent in 2021. The total regulation credits in 2021 were $144,298,222, an increase of 87.8 percent from $76,837,926 in 2020. The increase in regulation credits is due, in part, to a higher LOC component of regulation prices as a result of higher energy prices in 2021 compared to 2020.

When a resource offers into the regulation market, an estimated regulation LOC is added by PJM to form a total offer (units self scheduled or not providing in the energy market have a regulation LOC of zero). After a unit clears, the actual five minute interval LMP is used to calculate each unit's regulation LOC, update their total offers, and determine a marginal unit/clearing price in each five minute interval. This within hour calculation of total offers, including LOC, uses each cleared resource's rolling 100 hour average performance score. During settlements, each unit's regulation LOC and total offers are recalculated using each unit's within hour actual performance score. This recalculated LOC and offer using the actual within hour performance score is not used to recalculate the within hour clearing price. This means that the clearing price for the hour will not equal the actual clearing price. Where the resulting market price is lower than an individual resource offer adjusted for the within hour performance score, the resource is paid uplift to make up the difference.

The top ten units that received the most uplift in 2021 are shown in Table 10-45.

Table 10-45 Top 10 recipients of regulation uplift credits: 2021

Rank	Parent Company	Unit Name	Fuel Type	Total Regulation Uplift Credit	Share of Total Regulation Uplift Credits
1	Exelon Corporation	PE MUDDY RUN 1-8 H	HYDRO	$1,580,386	10.5%
2	American Electric Power Company Inc	AEP MITCHELL - KAMMER 2 F	COAL	$987,142	6.6%
3	Ontario Power Generation Inc	AP LKLYN 1-4 H	HYDRO	$545,910	3.6%
4	Atlantic Power Corporation	COM J375 MORRIS 1 CC	NATURAL GAS	$530,645	3.5%
5	American Electric Power Company Inc	AEP AMOS 1 F	COAL	$441,939	2.9%
6	American Electric Power Company Inc	AEP BIG SANDY 1 F	NATURAL GAS	$391,920	2.6%
7	American Municipal Power Inc	FE FREMONT ENERGY CENTER 3 CC	NATURAL GAS	$370,518	2.5%
8	Vistra Energy Corp	COM 935 KENDALL 3 CC	NATURAL GAS	$367,520	2.4%
9	American Electric Power Company Inc	AEP CLINCH RIVER 2 F	NATURAL GAS	$342,654	2.3%
10	American Electric Power Company Inc	AEP ROCKPORT 1 F	COAL	$342,023	2.3%
Total of Top 10				$5,900,657	39.3%
Total Regulation Uplift Credits				$15,018,116	100.0%

The uplift credits received for each unit type are shown in Table 10-46. The total uplift credits received increased 81.2 percent from $8,288,192 in 2020 to $15,018,116 in 2021. This increase, like the increase in total credits, is due in part to higher LOC components of regulation prices and offers as a result of higher energy prices in 2021 compared to 2020. Natural gas units had the largest increase in uplift payments, increasing from $2,387,575 (28.8 percent of total) in 2020, to $7,828,163 (52.1 percent of total) in 2021. Coal units had the largest decrease in uplift payments, decreasing from $3,675,577 (44.3 percent of total) in 2020, to $3,936,253 (26.2 percent of total) in 2021.

Table 10-46 PJM regulation by source: 2020 and 2021[98]

Year	Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2020	Battery	22	1,600,435	34.6%	$25,967,275	$0	$25,967,275
	Coal	19	344,862	7.5%	$5,131,262	$3,675,577	$8,806,839
	Hydro	27	774,796	16.8%	$10,963,914	$2,225,040	$13,188,954
	Natural Gas	180	1,826,396	39.5%	$25,137,267	$2,387,575	$27,524,842
	DR	21	78,939	1.7%	$1,354,339	$0	$1,354,339
Total		269	4,625,428.8	100.0%	$68,554,057	$8,288,192	$76,842,249
2021	Battery	23	1,538,257	33.3%	$45,184,072	$0	$45,184,072
	Coal	19	329,515	7.1%	$7,182,900	$3,936,253	$11,119,153
	Hydro	28	813,584	17.6%	$22,497,027	$3,253,700	$25,750,727
	Natural Gas	186	1,866,425	40.4%	$52,112,081	$7,828,163	$59,940,245
	DR	19	68,335	1.5%	$2,313,038	$0	$2,313,038
Total		275	4,616,116.0	100.0%	$129,289,119	$15,018,116	$144,307,235

98 Biomass data have been added to the natural gas category for confidentiality purposes.

Significant flaws in the regulation market design have led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have contributed to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-47).

Table 10-47 Active battery storage projects by submitted year: 2014 through 2021

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	5	61.0
2016	0	0.0
2017	1	2.0
2018	19	690.1
2019	60	3,933.7
2020	159	9,572.1
2021	310	24,032.6
Total	555	38,301.5

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the 2021 retire, the supply of regulation in PJM will be reduced by less than one percent.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 14, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours until January 9, 2017. A change to the regulation requirement was approved by the RMISTF in 2016, with an implementation date of January 9, 2017. The regulation requirement was increased from 700 effective MW to 800 effective MW during ramp hours (Table 10-36).

Table 10-48 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month. Changes in the actual MW required to satisfy the regulation requirement are the result of the amount of RegD actual MW cleared. When more RegD MW are cleared, the MBF is lower, resulting in those actual MW being worth less effective MW, requiring more actual MW to satisfy the requirement. When MBFs are higher, the actual MW of RegD are worth more effective MW, reducing the amount of actual MW needed to satisfy the requirement.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 481.6 hourly average performance adjusted actual MW in 2021. This is a decrease of 10.4 performance adjusted actual MW from 2020, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 492.0 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 707.3 hourly average performance adjusted actual MW in 2021. This is an increase of 4.9 performance adjusted actual MW from 2020, where the average hourly regulation cleared MW for ramp hours were 702.5 performance adjusted actual MW.

Table 10-48 Required regulation and ratio of supply to requirement: January 2020 through December 2021

		Average Required Regulation (MW)		Average Required Regulation (Effective MW)		Ratio of Supply MW to MW Requirement		Ratio of Supply Effective MW to Effective MW Requirement	
Hours	Month	2020	2021	2020	2021	2020	2021	2020	2021
Ramp	Jan	712.9	713.2	800.1	800.0	1.36	1.59	1.25	1.42
	Feb	694.3	709.7	800.0	800.0	1.31	1.53	1.22	1.37
	Mar	692.5	713.8	800.1	800.0	1.33	1.54	1.24	1.38
	Apr	707.5	702.8	800.1	800.0	1.41	1.48	1.29	1.33
	May	711.8	705.5	800.1	800.0	1.42	1.45	1.31	1.32
	Jun	705.5	698.8	800.0	799.9	1.52	1.50	1.38	1.36
	Jul	702.8	699.0	800.1	799.9	1.57	1.54	1.42	1.38
	Aug	705.1	707.4	800.0	800.0	1.47	1.58	1.34	1.43
	Sep	694.8	710.7	799.8	800.0	1.46	1.47	1.33	1.35
	Oct	696.0	712.9	800.1	799.9	1.46	1.44	1.33	1.32
	Nov	700.9	708.4	800.1	800.0	1.43	1.41	1.30	1.30
	Dec	705.5	705.7	800.1	799.9	1.56	1.51	1.40	1.38
Nonramp	Jan	479.5	495.1	525.1	525.2	1.43	1.52	1.33	1.42
	Feb	495.9	500.4	525.1	525.1	1.45	1.59	1.37	1.47
	Mar	493.1	495.9	525.1	525.2	1.36	1.59	1.29	1.47
	Apr	492.7	490.9	525.2	525.1	1.46	1.51	1.36	1.41
	May	486.6	487.1	525.3	525.5	1.45	1.54	1.36	1.43
	Jun	490.0	478.6	525.1	525.4	1.45	1.50	1.36	1.39
	Jul	498.1	475.5	525.4	525.1	1.46	1.51	1.38	1.40
	Aug	489.8	474.4	525.0	525.2	1.43	1.60	1.35	1.47
	Sep	484.8	470.9	525.2	525.1	1.46	1.58	1.36	1.44
	Oct	491.3	471.8	525.2	525.1	1.50	1.51	1.41	1.39
	Nov	501.8	468.8	525.5	525.0	1.50	1.45	1.41	1.34
	Dec	500.8	469.5	525.1	525.0	1.63	1.57	1.50	1.42

Market Concentration

In 2021, the effective MW weighted average HHI of RegA resources was 2215 which is highly concentrated and the weighted average HHI of RegD resources was 1585 which is moderately concentrated. The weighted average HHI of all resources was 1205, which is moderately concentrated. The weighted average HHI reflects the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-49 includes a monthly summary of three pivotal supplier (TPS) results. In 2021, the three pivotal supplier test was failed in 85.9 percent of hours. In 2021, the actual MW weighted average HHI of RegA resources was 2215 which is highly concentrated and the weighted average HHI of RegD resources was 1585 which is moderately concentrated. The weighted average HHI of all resources was 1205, which is moderately concentrated. The MMU concludes that the PJM Regulation Market in 2021 was characterized by structural market power. The results presented here are calculated by PJM. The MMU has been unable to verify these results, as some of the underlying data necessary to replicate these calculations are not saved. PJM has submitted a request to the vendor to save all data necessary for verification.

Table 10-49 Regulation market monthly three pivotal supplier results: 2019 through 2021

	Percent of Hours Pivotal		
Month	2019	2020	2021
Jan	77.8%	99.1%	91.4%
Feb	76.0%	97.4%	88.7%
Mar	93.3%	98.3%	87.2%
Apr	93.1%	96.5%	88.5%
May	94.0%	94.9%	83.9%
Jun	91.0%	89.8%	86.4%
Jul	92.7%	89.0%	86.4%
Aug	93.1%	94.6%	76.3%
Sep	93.3%	93.3%	82.9%
Oct	96.1%	94.0%	91.9%
Nov	90.7%	91.0%	86.7%
Dec	96.1%	83.6%	80.1%
Average	90.6%	93.5%	85.9%

Market Conduct

Offers

Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[99] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100 per MW) by 14:15 the day before the operating day.[100]

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00 per MW margin. The $12.00 margin embeds market power in the regulation offers, is not part of the cost of regulation, and should be eliminated. The performance component for cost-based offers is not to exceed the increased costs (increased short run marginal costs including increased fuel costs) resulting from moving the unit up and down to provide regulation. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. There is an energy storage loss component for batteries and flywheels as a cost component of regulation performance offers to reflect the net energy consumed to provide regulation service.[101]

Up until one hour before the operating hour, the regulating resource must provide: status (available, unavailable, or self scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW); and the regulation signal type (RegA or RegD). Resources may offer regulation for both the RegA and RegD signals, but will be assigned to follow only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they are willing to provide.[102]

All LSEs are required to provide regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-51).[103] Figure 10-17 compares average hourly regulation and self scheduled regulation during ramp and nonramp hours on an effective MW basis. The average hourly regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.[104] Self scheduled regulation comprised an average of 46.0 percent during ramp hours and 61.3 percent during nonramp hours in 2021.

Figure 10-17 Nonramp and ramp regulation levels: January 2020 through December 2021

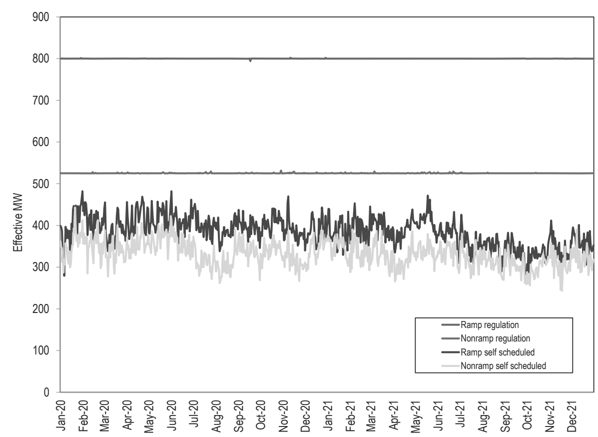


Table 10-50 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 46.9 percent of the total effective MW in December 2021) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in October 2012 and 70.1 percent of all self scheduled

99 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 116 (September 1, 2021).
100 Id. at 3.2.2, at p 62.
101 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 37 (Dec. 9, 2020).
102 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 116 (September 1, 2021).
103 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 85 (September 1, 2021).
104 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 116 (September 1, 2021).

effective MW in December 2021). In 2021, the average RegD percentage of total self scheduled effective MW was 71.7 percent, an increase of 0.5 percentage points from 2020, when the average was 71.2 percent.

Table 10-50 RegD self scheduled regulation by month: January 2020 through December 2021

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	RegD Percent of Total Self Scheduled Effective MW	RegD Percent of Total Effective MW
2020	Jan	253.3	311.9	376.5	674.0	67.3%	46.3%
2020	Feb	263.6	333.5	385.3	674.0	68.4%	49.5%
2020	Mar	257.9	319.9	358.9	639.9	71.9%	50.0%
2020	Apr	267.2	318.1	382.9	639.7	69.8%	49.7%
2020	May	274.6	312.2	388.5	639.8	70.7%	48.8%
2020	Jun	281.8	335.1	390.5	696.7	72.2%	48.1%
2020	Jul	252.6	343.3	369.3	697.1	68.4%	49.2%
2020	Aug	258.7	341.0	357.2	697.0	72.4%	48.9%
2020	Sep	275.4	317.2	363.3	639.6	75.8%	49.6%
2020	Oct	265.7	319.2	368.3	639.8	72.1%	49.9%
2020	Nov	255.1	321.4	346.5	640.6	73.6%	50.2%
2020	Dec	262.1	329.8	366.8	674.0	71.4%	48.9%
2020 Average		264.0	325.2	371.2	662.7	71.2%	49.1%
2021	Jan	250.5	322.4	367.7	674.0	68.1%	47.8%
2021	Feb	262.0	335.3	366.7	674.3	71.4%	49.7%
2021	Mar	263.0	321.7	359.0	639.9	73.3%	50.3%
2021	Apr	266.0	325.9	343.1	639.6	77.5%	51.0%
2021	May	256.8	320.6	368.0	639.9	69.8%	50.1%
2021	Jun	266.5	329.9	362.7	697.0	73.5%	47.3%
2021	Jul	255.4	331.6	344.6	696.9	74.1%	47.6%
2021	Aug	242.6	326.1	330.2	698.9	73.5%	46.7%
2021	Sep	219.8	302.0	319.6	639.6	68.8%	47.2%
2021	Oct	223.6	301.0	311.1	639.8	71.9%	47.1%
2021	Nov	218.5	298.9	321.2	640.3	68.0%	46.7%
2021	Dec	239.3	316.3	341.4	673.9	70.1%	46.9%
2021 Average		247.0	332.0	344.6	662.8	71.7%	48.2%

LSE's can satisfy their obligation to provide regulation by purchasing in the spot market, self scheduling, or through bilateral agreements. Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in 2021, 52.0 percent was purchased in the PJM market, 44.1 percent was self scheduled, and 3.9 percent was purchased bilaterally (Table 10-51). Table 10-52 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for January through December, 2012 through 2021. Table 10-51 and Table 10-52 are based on settled (purchased) MW.

Table 10-51 Regulation sources: spot market, self scheduled, bilateral purchases: January 2020 through December 2021

Year	Month	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2020	Jan	179,061.4	46.2%	190,434.8	49.1%	18,166.0	4.7%	387,662.1
2020	Feb	160,674.9	43.8%	185,702.6	50.6%	20,815.5	5.7%	367,193.0
2020	Mar	175,560.8	46.5%	181,566.1	48.1%	20,266.0	5.4%	377,392.8
2020	Apr	154,642.4	42.4%	187,819.3	51.5%	22,195.5	6.1%	364,657.2
2020	May	167,682.0	44.2%	191,949.3	50.5%	20,125.5	5.3%	379,756.8
2020	Jun	192,336.9	49.3%	178,239.7	45.7%	19,479.5	5.0%	390,056.1
2020	Jul	189,151.3	46.4%	198,595.7	48.7%	19,997.5	4.9%	407,744.5
2020	Aug	207,948.6	51.1%	181,392.4	44.6%	17,756.0	4.4%	407,097.0
2020	Sep	181,955.4	49.6%	171,428.3	46.7%	13,358.0	3.6%	366,741.7
2020	Oct	178,179.3	46.9%	186,687.3	49.1%	15,309.5	4.0%	380,176.1
2020	Nov	180,188.6	48.9%	172,941.0	46.9%	15,668.5	4.2%	368,798.1
2020	Dec	189,587.0	47.8%	188,798.6	47.6%	18,505.0	4.7%	396,890.6
Total		2,156,968.5	47.0%	2,215,555.1	48.2%	221,642.5	4.8%	4,594,166.0
2021	Jan	186,762.8	46.6%	192,708.2	48.1%	21,466.0	5.4%	400,937.0
2021	Feb	172,967.1	47.4%	174,470.7	47.9%	17,095.5	4.7%	364,533.3
2021	Mar	182,812.8	47.3%	189,176.1	48.9%	14,910.0	3.9%	386,898.9
2021	Apr	190,444.5	51.0%	170,255.4	45.6%	12,763.0	3.4%	373,462.9
2021	May	171,841.5	44.5%	198,026.9	51.3%	16,270.0	4.2%	386,138.5
2021	Jun	211,800.7	54.2%	163,167.4	41.8%	15,526.0	4.0%	390,494.1
2021	Jul	225,587.1	55.9%	162,774.7	40.4%	15,017.5	3.7%	403,379.4
2021	Aug	234,148.0	57.9%	154,435.7	38.2%	15,577.5	3.9%	404,161.2
2021	Sep	190,656.5	53.7%	150,785.2	42.4%	13,896.0	3.9%	355,337.7
2021	Oct	212,564.6	57.0%	150,788.9	40.4%	9,873.5	2.6%	373,226.9
2021	Nov	191,647.2	53.7%	151,450.1	42.4%	13,883.0	3.9%	356,980.3
2021	Dec	211,012.8	54.1%	164,679.9	42.2%	14,258.5	3.7%	389,951.2
Total		2,382,245.5	52.0%	2,022,719.3	44.1%	180,536.5	3.9%	4,585,501.3

Table 10-52 Regulation sources: 2012 through 2021

Year	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2012	6,149,110.0	78.6%	1,484,446.2	19.0%	193,408.0	2.5%	7,826,964.2
2013	3,088,963.1	57.7%	2,064,156.7	38.5%	204,260.5	3.8%	5,357,380.3
2014	2,327,322.4	49.3%	2,161,996.5	45.8%	231,218.0	4.9%	4,720,536.9
2015	2,546,688.3	54.4%	1,888,040.0	40.3%	250,386.1	5.3%	4,685,114.3
2016	2,260,701.6	48.6%	2,104,775.1	45.2%	287,809.5	6.2%	4,653,286.2
2017	2,504,264.1	55.2%	1,783,045.7	39.3%	250,184.5	5.5%	4,537,494.3
2018	2,755,355.7	60.5%	1,558,388.9	34.2%	243,589.5	5.3%	4,557,334.1
2019	2,367,346.1	53.1%	1,867,285.3	41.9%	221,292.5	5.0%	4,455,923.9
2020	2,156,968.5	47.0%	2,215,555.1	48.2%	221,642.5	4.8%	4,594,166.0
2021	2,382,245.5	52.0%	2,022,719.3	44.1%	180,536.5	3.9%	4,585,501.3

In 2021, DR provided an average of 10.9 MW of regulation per hour during ramp hours (12.4 MW of regulation per hour during ramp hours in 2020), and an average of 7.4 MW of regulation per hour during nonramp hours (9.2 MW of regulation per hour during nonramp hours in 2020). Generating units supplied an average of 696.0 MW of regulation per hour during ramp hours in 2021 (690.5 MW of regulation per hour during ramp hours in 2020), and an average of 474.3 MW per hour during nonramp hours in 2021 (482.8 MW of regulation per hour during nonramp hours in 2020).

Market Performance

Price

Table 10-53 shows the regulation price and regulation cost per MW for 2009 through 2021. The weighted average RMCP for 2021 was $26.00 per MW. This is an increase of $12.45 per MW, or 91.9 percent, from the weighted average RMCP of $13.55 per MW in 2020. This increase in the regulation clearing price was the result of an increase in energy prices in 2021 and the related increase in the opportunity cost component of RMCP.

Table 10-53 Comparison of average price and cost for regulation: 2009 through 2021

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent of Cost
2009	$23.00	$30.68	75.0%
2010	$18.00	$32.86	54.8%
2011	$16.49	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.49	$53.82	82.7%
2015	$31.92	$38.36	83.2%
2016	$15.73	$18.13	86.7%
2017	$16.79	$23.03	72.9%
2018	$25.32	$31.94	79.3%
2019	$16.27	$20.32	80.1%
2020	$13.55	$16.73	81.0%
2021	$26.00	$31.49	82.6%

The introduction of fast start pricing in the PJM energy market on September 1, 2021, had an effect on the regulation market LOC included in regulation offers and in the resulting clearing price for regulation. Table 10-54 shows the effect of fast start pricing on the regulation market monthly component of price from September through December, 2021.

Table 10-54 Comparison of fast start and dispatch and pricing components: September through December, 2021

		Weighted Average Price ($/Perf. Adj. Actual MW)		
Month	Pricing Method	Capability Clearing Price	Performance Clearing Price	Regulation Market Clearing Price
Sep	Fast Start	$29.08	$1.34	$30.41
	Dispatch	$27.22	$1.34	$28.55
Oct	Fast Start	$39.92	$1.47	$41.40
	Dispatch	$35.64	$1.47	$37.12
Nov	Fast Start	$54.40	$1.88	$56.28
	Dispatch	$50.56	$1.88	$52.43
Dec	Fast Start	$27.37	$1.42	$28.79
	Dispatch	$25.62	$1.42	$27.05

Figure 10-18 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC). Then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). The capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-18 illustrates the components of the regulation market clearing price. Each section represents the contribution of the lost opportunity cost (green area), capability price (blue area), and performance price (orange area), to the total price. From this figure, it is clear that the lost opportunity cost is the predominant component of the total clearing price.

Figure 10-18 Regulation market clearing price components (Dollars per MW): 2021

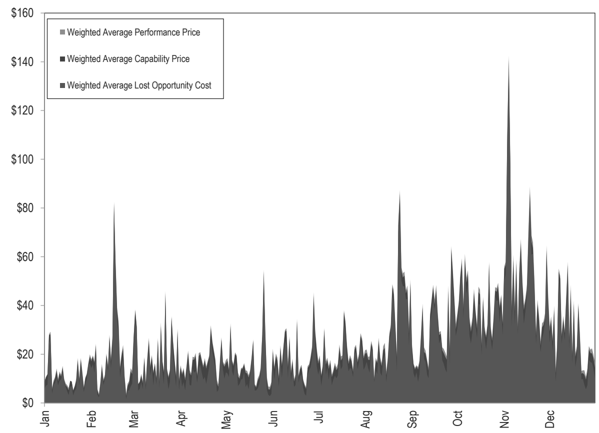


Table 10-55 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-18 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-55 Regulation market monthly component of price (Dollars per MW): 2021

Month	Weighted Average Regulation Market Capability Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Performance Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Clearing Price ($/Perf. Adj. Actual MW)
Jan	$11.50	$0.62	$12.12
Feb	$19.64	$0.96	$20.60
Mar	$18.48	$0.68	$19.20
Apr	$16.40	$0.95	$17.34
May	$15.77	$0.86	$16.63
Jun	$18.26	$0.97	$19.22
Jul	$18.98	$1.05	$20.02
Aug	$31.77	$1.36	$33.13
Sep	$29.08	$1.34	$30.41
Oct	$39.92	$1.47	$41.40
Nov	$54.40	$1.88	$56.28
Dec	$27.37	$1.42	$28.79
Average	$24.88	$1.12	$26.00

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-56. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in 2021 was $144.4 million, compared to $76.9 million in 2020.

Table 10-56 Total regulation charges: 2020 through 2021

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2020	Jan	387,662.1	$6,495,664	$13.70	$16.76	81.7%
2020	Feb	367,193.0	$4,630,253	$10.12	$12.61	80.3%
2020	Mar	377,392.8	$4,619,257	$9.06	$12.24	74.0%
2020	Apr	364,657.2	$5,646,138	$12.10	$15.48	78.1%
2020	May	379,756.8	$6,078,957	$12.97	$16.01	81.0%
2020	Jun	390,056.1	$6,072,212	$12.31	$15.57	79.1%
2020	Jul	407,744.5	$7,732,029	$16.14	$18.96	85.1%
2020	Aug	407,097.0	$7,566,611	$15.36	$18.59	82.6%
2020	Sep	366,741.7	$4,909,677	$10.88	$13.39	81.2%
2020	Oct	380,176.1	$8,168,776	$17.64	$21.49	82.1%
2020	Nov	368,798.1	$7,381,789	$15.95	$20.02	79.7%
2020	Dec	396,890.6	$7,562,483	$15.79	$19.05	82.9%
Yearly		4,594,166.0	$76,860,642	$13.55	$16.73	81.0%
2021	Jan	400,937.0	$6,038,564	$12.12	$15.06	80.5%
2021	Feb	364,533.3	$9,401,619	$20.60	$25.79	79.9%
2021	Mar	386,898.9	$8,793,373	$19.20	$22.73	84.5%
2021	Apr	373,462.9	$7,951,303	$17.34	$21.29	81.5%
2021	May	386,138.5	$8,051,297	$16.62	$20.85	79.7%
2021	Jun	390,494.1	$9,654,112	$19.22	$24.72	77.8%
2021	Jul	403,379.4	$9,696,300	$20.02	$24.04	83.3%
2021	Aug	404,161.2	$15,414,276	$33.13	$38.14	86.9%
2021	Sep	355,337.7	$12,923,840	$30.41	$36.37	83.6%
2021	Oct	373,226.9	$18,334,407	$41.40	$49.12	84.3%
2021	Nov	356,980.3	$24,453,797	$56.28	$68.50	82.2%
2021	Dec	389,951.2	$13,662,814	$28.79	$35.04	82.2%
Yearly		4,585,501.3	$144,375,702	$26.00	$31.49	82.6%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-57. Total scheduled regulation is based on settled performance adjusted MW. In 2021, the average total cost of regulation was $31.49 per MW, 88.2 percent higher than $16.73 in 2020. In 2021, the monthly average capability component cost of regulation was $25.25, 92.9 percent higher than $13.09 in 2020. In 2021, the monthly average performance component cost of regulation was $2.94, 60.8 percent higher than $1.83 in 2020. The increase of the average total cost in 2021 versus 2020, was primarily a result of higher LOC values due to higher prices in the energy market.

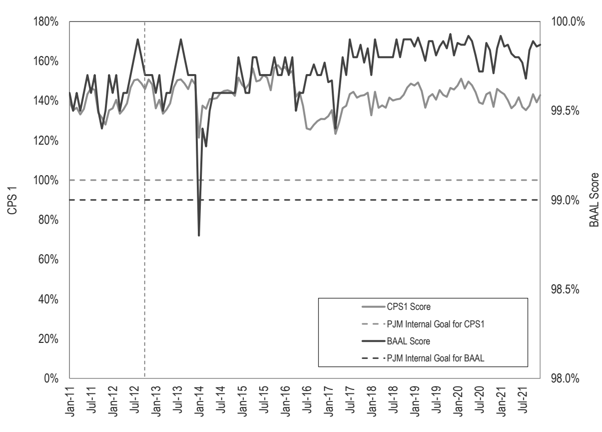
Table 10-57 Components of regulation cost: January 2020 through December 2021

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2020	Jan	387,662.1	$13.32	$1.80	$1.64	$16.76
	Feb	367,193.0	$9.90	$1.35	$1.36	$12.61
	Mar	377,392.8	$8.71	$1.46	$2.07	$12.24
	Apr	364,657.2	$11.68	$1.77	$2.03	$15.48
	May	379,756.8	$12.66	$1.39	$1.95	$16.01
	Jun	390,056.1	$11.74	$1.94	$1.88	$15.57
	Jul	407,744.5	$15.74	$1.54	$1.68	$18.96
	Aug	407,097.0	$14.80	$2.01	$1.78	$18.59
	Sep	366,741.7	$10.42	$1.49	$1.47	$13.39
	Oct	380,176.1	$16.90	$2.80	$1.78	$21.49
	Nov	368,798.1	$15.21	$2.70	$2.11	$20.02
	Dec	396,890.6	$15.40	$1.72	$1.94	$19.05
Yearly		4,594,166.0	$13.09	$1.83	$1.81	$16.73
2021	Jan	400,937.0	$11.71	$1.67	$1.68	$15.06
	Feb	364,533.3	$19.90	$2.52	$3.37	$25.79
	Mar	386,898.9	$18.70	$1.86	$2.16	$22.73
	Apr	373,462.9	$16.63	$2.66	$2.00	$21.29
	May	386,138.5	$15.87	$2.40	$2.58	$20.85
	Jun	390,494.1	$18.45	$2.54	$3.73	$24.72
	Jul	403,379.4	$19.25	$2.68	$2.10	$24.04
	Aug	404,161.2	$32.19	$3.36	$2.58	$38.14
	Sep	355,337.7	$29.45	$3.41	$3.52	$36.37
	Oct	373,226.9	$40.60	$3.97	$4.55	$49.12
	Nov	356,980.3	$55.46	$4.80	$8.24	$68.50
	Dec	389,951.2	$27.87	$3.67	$3.50	$35.04
Total		4,585,501.3	$25.25	$2.94	$3.29	$31.49

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-19 for every month from January 2011 through December 2021 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[105] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-19 Monthly CPS1 and BAAL performance: January 2011 through December 2021



105 See *2019 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[106] Although PJM has raised the issue, there are no firm fuel requirements for black start units.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of cost of service rates defined in the tariff.[107]

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service may be across zones. Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.

On April 7, 2021, PJM issued an incremental RFP for additional black start service in the BGE and PEPCO Zones. The RFP is a two stage process. Level one submissions were due May 10, 2021. Level two submissions were due May 31, 2021. On November 1, 2021, PJM made awards for the April 7, 2021 incremental RFP. The planned in service date is April 1, 2023.[108]

Total black start charges are the sum of black start revenue requirement charges and black start uplift (operating reserve) charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor applicable when CRF rates are not used. The tariff specifies how to calculate each component of the revenue requirement formula.[109] Black start resources can choose to recover fixed costs under a formula rate based on zonal Net CONE and unit ICAP rating, a cost recovery rate based on incremental black start NERC-CIP compliance capital costs, or a cost recovery rate based on FERC-approved rate plus capital costs for new investment. In addition, PJM applies a cost recovery rate based on incremental black start equipment capital costs.

Black start uplift (operating reserve) charges are paid to units committed in real time to provide black start service or for black start testing.[110] Total black start charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.[111] It is not clear why it is reasonable to have different charges for black start service across zones as the service is to ensure that PJM as a whole can recover from a large scale outage.

In 2021, total black start charges were $67.96 million, an increase of $3.09 million (4.76 percent) from 2020. Uplift charges for black start service increased from $0.23 million 2020 to $0.32 million (37.1 percent) in 2021. Table 10-58 shows total charges each year from 2010 through 2021.[112]

Table 10-58 Black start revenue requirement charges: 2010 through 2021

Year	Revenue Requirement Charges	Uplift Charges	Total
2010	$11,490,379	$0	$11,490,379
2011	$13,695,331	$0	$13,695,331
2012	$18,749,617	$8,384,651	$27,134,269
2013	$20,874,535	$86,701,561	$107,576,097
2014	$26,945,112	$32,906,733	$59,851,845
2015	$56,425,648	$5,175,644	$61,601,292
2016	$69,376,257	$279,017	$69,655,275
2017	$69,258,169	$257,174	$69,515,342
2018	$64,439,926	$294,753	$64,734,679
2019	$64,327,918	$226,014	$64,553,932
2020	$64,643,080	$230,754	$64,873,834
2021	$67,645,753	$316,437	$67,962,190

Black start zonal charges in 2021 ranged from $43,630 in the BGE Zone to $19,803,649 in the AEP Zone. For each zone, Table 10-59 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). Customers paid an average of $1.16 per MW-day for black start service in 2021.

106 OATT Schedule 1 § 1.3BB.
107 *See* OATT Schedule 6A para. 18.
108 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.
109 *See* OATT Schedule 6A para. 18.
110 There are no black start units currently using the ALR option.
111 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
112 Starting December 1, 2012, PJM defined a separate black start uplift category. ALR units accounted for the high uplift charges in 2013 – 2015. All ALR units had been replaced by April 2015.

Table 10-59 Black start zonal charges: 2020 and 2021[113]

	2020					2021				
Zone	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)
ACEC	$2,572,240	$10,709	$2,582,949	2,737	$2.58	$2,256,528	$26,011	$2,282,539	2,635	$2.37
AEP	$17,243,608	$26,537	$17,270,145	22,498	$2.10	$19,741,659	$61,990	$19,803,649	21,615	$2.51
APS	$3,813,141	$1,159	$3,814,300	9,596	$1.09	$5,322,896	$1,135	$5,324,031	8,638	$1.69
ATSI	$5,574,883	$10,481	$5,585,364	12,567	$1.21	$5,581,214	$6,593	$5,587,807	12,465	$1.23
BGE	$138,490	$628	$139,118	6,706	$0.06	$43,535	$95	$43,630	6,700	$0.02
COMED	$8,176,146	$22,638	$8,198,784	20,949	$1.07	$9,353,385	$36,616	$9,390,000	20,220	$1.27
DAY	$218,116	$14,120	$232,236	3,259	$0.19	$233,178	$13,958	$247,136	3,309	$0.20
DUKE	$357,187	$13,990	$371,177	5,052	$0.20	$384,287	$12,598	$396,885	4,975	$0.22
DUQ	$43,485	$15,810	$59,295	2,662	$0.06	$271,036	$1,338	$272,374	2,668	$0.28
DOM	$4,856,415	$23,222	$4,879,637	19,931	$0.67	$5,226,310	$56,494	$5,282,803	20,061	$0.72
DPL	$2,147,289	$17,353	$2,164,642	4,098	$1.44	$1,621,172	$15,479	$1,636,651	4,086	$1.10
EKPC	$324,084	$1,641	$325,725	3,074	$0.29	$332,380	$2,076	$334,456	2,720	$0.34
JCPLC	$2,753,548	$3,058	$2,756,606	6,057	$1.24	$677,277	$2,564	$679,841	5,903	$0.32
MEC	$388,691	$28,169	$416,860	2,986	$0.38	$500,219	$20,033	$520,253	2,976	$0.48
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$1,394,979	$1,261	$1,396,240	8,428	$0.45	$1,459,560	$2,199	$1,461,759	8,148	$0.49
PE	$4,327,013	$8,952	$4,335,964	3,015	$3.93	$4,368,997	$12,851	$4,381,848	2,911	$4.12
PEPCO	$1,549,645	$7,218	$1,556,864	6,191	$0.69	$331,735	$10,971	$342,707	5,887	$0.16
PPL	$3,059,144	$10,441	$3,069,585	7,939	$1.06	$4,876,895	$10,154	$4,887,050	7,260	$1.84
PSEG	$2,513,183	$2,350	$2,515,534	9,753	$0.70	$1,749,798	$9,300	$1,759,098	9,557	$0.50
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$3,191,793	$11,017	$3,202,810	8,201	$1.07	$3,313,690	$13,983	$3,327,673	7,866	$1.16
Total	$64,643,080	$230,754	$64,873,834	165,696	$1.07	$67,645,753	$316,437	$67,962,190	160,599	$1.16

Table 10-60 provides a revenue requirement estimate by zone for the 2021/2022, 2022/2023, and 2023/2024 Delivery Years.[114] Revenue requirement values are rounded up to the nearest $50,000 to reflect uncertainty about future black start revenue requirement costs. These values are illustrative only. The estimates are based on the best available data including current black start unit revenue requirements, expected black start unit termination and in service dates, changes in recovery rates, and owner provided cost estimates of incoming black start units at the time of publication and may change significantly.

Table 10-60 Black start zonal revenue requirement estimate: 2021/2022 through 2023/2024 Delivery Years

Zone	2021 / 2022 Revenue Requirement	2022 / 2023 Revenue Requirement	2023 / 2024 Revenue Requirement
ACEC	$2,150,000	$2,150,000	$2,150,000
AEP	$20,800,000	$20,550,000	$20,600,000
APS	$7,950,000	$7,950,000	$7,950,000
ATSI	$5,900,000	$5,900,000	$5,900,000
BGE	$50,000	$50,000	$350,000
COMED	$10,050,000	$9,400,000	$9,500,000
DAY	$300,000	$250,000	$250,000
DUKE	$450,000	$350,000	$350,000
DUQ	$2,150,000	$2,100,000	$2,100,000
DOM	$5,550,000	$5,350,000	$5,400,000
DPL	$1,350,000	$1,250,000	$1,300,000
EKPC	$400,000	$300,000	$300,000
JCPLC	$650,000	$550,000	$600,000
MEC	$550,000	$450,000	$500,000
OVEC	$0	$0	$0
PECO	$1,600,000	$1,350,000	$1,400,000
PE	$4,650,000	$4,550,000	$4,600,000
PEPCO	$300,000	$200,000	$650,000
PPL	$5,350,000	$5,200,000	$5,250,000
PSEG	$1,950,000	$1,850,000	$1,850,000
REC	$0	$0	$0
Total	$72,150,000	$69,750,000	$71,000,000

113 Peak load for each zone is used to calculate the black start rate per MW day.
114 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

CRF Issues

The capital recovery factor (CRF) defines the revenue requirement of black start units when new equipment is added to provide black start capability.[115] The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. CRFs are calculated using a formula (or a correctly defined standard financial model) that accounts for the weighted average cost of capital and its components, plus depreciation and taxes. The PJM CRF table was created in 2007 as part of the new RPM capacity market design and incorporated in Attachment DD to the PJM OATT (Table 10-61). The CRF table provided for the accelerated return of incremental investment in capacity resources based on concerns about the fact that some old coal units would be making substantial investments related to pollution control. The CRF values were later added to the black start rules.[116] The CRF table in the tariff included assumptions about tax rates that were significantly too high after the changes to the tax code in 2017. The PJM tariff tables including CRF values should have been changed for both black start and the capacity market when the tax laws changed in 2017.

Table 10-61 CRF table for existing black start units

Age of Black Start Unit (Years)	Term of Black Start Unit Commitment (Years)	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

The CRF table for existing black start units includes the column header, term of black start unit commitment, which is misleading and incorrect. The column is simply the cost recovery period. Accelerated recovery reduces risk to black start units and should not be the basis for a shorter commitment. Full payment of all costs of black start investment on an accelerated basis should not be a reason for a shortened commitment period. Regardless of the recovery period, payment of the full costs of the black start investment should require commitment for the life of the unit.[117] In addition, there is no need for such short recovery periods for black start investment costs. Two periods, based on unit age, are more than adequate.

The U.S. Internal Revenue Code changed significantly in December 2017. The PJM CRF table did not change to reflect these changes. As a result, CRF values have overcompensated black start units since the changes to the tax code. The new tax law allow for a more accelerated depreciation and reduced the corporate tax rate to 21 percent.

Updated CRF rates, incorporating the tax code changes and applicable to all black start units, should be implemented immediately. The updated CRF rates should apply to all black start units because the actual tax payments for all black start units were reduced by the tax law changes. Without this change, black start units are receiving and will continue to receive an unexpected and inappropriate windfall.

On April 7, 2021, PJM filed with FERC to update the CRF values for new black start service units.[118] PJM proposed to bifurcate the CRF calculation, applying an updated CRF calculation that incorporates the new federal tax law to new black start units while leaving the outdated and incorrect CRF in place for existing black start units. Rather than fix the inaccurate CRF values used for existing black units, PJM's filing would have made the use of inaccurate values permanent. The MMU filed comments on April 28, 2021.[119] The MMU objected to the continued use of the outdated CRF for existing units. The MMU also introduced a CRF formula for calculating the CRF for new black start units and requested that the CRF formula be included in the tariff.[120] [121] On August 10, 2021, FERC issued an order ("August 10th Order") that accepted PJM's tariff revisions that apply to new black start units (starting service after June 6, 2021) and directed PJM to include the CRF formula proposed by the MMU.[122] The August 10th Order also established a show cause proceeding in a new docket to "determine whether the existing rates for generating units providing Black Start Service (Black Start Units), which are based on a federal corporate income tax that pre-dates the Tax Cuts and Jobs Act of 2017 (TCJA), remains just and reasonable."[123] The MMU requested rehearing

115 *See* OATT Schedule 6A para. 18.
116 *Id.*
117 PJM's recent filing to revise Schedule 6A includes a required commitment to provide black start service for the life of the unit. See FERC Docket No. ER21-1635.

118 *See* Docket No. ER21-1635-000.
119 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000 (April 28, 2021), which can be accessed at <http://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1635_20210428.pdf>.
120 Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
121 Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
122 176 FERC ¶ 61,080 at 42 and 44 (2021).
123 176 FERC ¶ 61,080 at 2 (2021).

over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[124] [125] The request for rehearing was denied.[126] PJM's compliance filing to address the August 10 Order was accepted by letter order, subject to edits proposed by the MMU, on December 16, 2021.[127]

PJM's response to the show cause directive in the August 10th Order continued to support the use of the outdated CRF despite the Commission's statement that the CRF values "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[128] [129] The MMU responded with analysis showing that PJM's proposal for maintaining the outdated CRF values would result in $126 million of over recovery of black start capital investments.[130]

The MMU also proposed an update to the CRF that reflects the return of capital already received by existing black start units and eliminates the over recovery that occurs under the PJM proposal. The updated CRF would be set at the level that covers the tax liabilities going forward, pays a return at the required rates on the remaining capital investment, pays back the full investment and results in the required return on and of capital over the CRF term. A description of the MMU's proposal and a formula for calculating the updated CRF are included in the MMU Comments.[131]

NERC – CIP

No black start units have requested new or additional black start NERC – CIP Capital Costs.[132]

Minimum Tank Suction Level (MTSL)

PJM had permitted and in some cases required black start unit owners to charge customers for 100 percent of oil tanks even when the black start use was shared with another facility and the black start use was only a very small share of the oil tank use. The MMU had recommended since 2017 that when black start resources share oil tanks with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU had also recommended that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks.

This recommendation was filed by PJM and approved by FERC.[133]

Reactive Power Service and Capability

Suppliers of reactive power are compensated separately for reactive power service and reactive capability.

Compensation for reactive power service is based on real-time lost opportunity costs.[134] Reactive service is generally provided by units reducing real power output in order to increase reactive power output. These units are paid uplift based on lost opportunity costs.[135]

Compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT. Resources may obtain FERC approval to recover a reactive revenue requirement, the reactive capability rate, from PJM customers.[136]

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources of reactive power (such as static VAR compensators and capacitor banks).[137] PJM in its role as the independent RTO and transmission provider determines the reactive capability it needs from all sources in order to reliably operate the grid. PJM, as part of its Interconnection Agreement, requires that all resources over 20 MW be able to operate at a power factor of 0.90 lagging to 0.95 leading throughout their entire operating range. Reactive power helps maintain appropriate voltages on the transmission system and must be sourced locally.

124 Id. at 50.
125 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
126 177 FERC ¶ 62,017 (2021).
127 177 FERC ¶ 61,202 (2021).
128 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
129 August 10th Oder at 47.
130 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).
131 Id. (Attachment B, Section H at 18).
132 OATT Schedule 6A para. 21. "The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit."
133 See 176 FERC ¶ 61,080 (2021).
134 See OA Schedule 1 § 3.2.3B.
135 Id.
136 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 93 (Aug. 31, 2020).
137 OATT Schedule 2.

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements. Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers proportionally to their zone and to any nonzone (outside of PJM) peak transmission use and daily average point to point transmission reservations.[138 139]

In 2016, FERC began to reexamine its policies on reactive compensation.[140] More recently, on November 18, 2021, the FERC issued a notice of inquiry concerning reactive power capability compensation.[141]

Issues with Reactive Capability Market Design

The Market Monitor appreciates that the Commission is investigating these issues related to reactive power compensation in wholesale power markets. The NOI inquires about reactive power capability compensation under the AEP Method, alternative methods of compensation, and resources interconnected at the distribution level. The fundamental question is whether market design in the organized wholesale markets requires separate, guaranteed cost of service compensation for reactive capability. The answer is no. In the PJM market design, investment in resources is fully recoverable through markets. The PJM markets are a complete set of markets that are self sustaining. Unlike some ISO/RTO designs, the PJM market relies on markets rather than cost of service regulation or bilateral contracts to pay for capacity. Generators will invest in markets when the expected revenues provide for the payment of all costs and the return and of capital. That is the way competitive markets work. It would be more equitable, more consistent with the PJM competitive market design, and more consistent with appropriate compensation for all generator costs, including reactive, to rely on PJM markets than to continue the outdated mixing of regulatory paradigms.

Even if the PJM design worked in the way asserted by supporters of cost of service payments for reactive, the best possible outcome would be the same as the market outcome. There would be an opportunity to recover all costs. A simple application of Occam's razor implies that the market approach should be used, as it is overwhelmingly more efficient than the current rate case, cost of service approach. Supporters of the cost of service approach have never explained why a nonmarket approach is required in PJM or why it is preferable to a market approach.

The current process is an inefficient waste of time because it relies on an atavistic regulatory paradigm that is not relevant in the PJM market framework. The AEP Method was created, before the creation of the PJM markets, by a regulated utility that had regulatory and financial reasons to want to define some generation costs as transmission costs. There is no reason to include complex rules that arbitrarily segregate a portion of a resource's capital costs as related to reactive power and that require recovery of that arbitrary portion through guaranteed revenue requirement payments based on burdensome cost of service rate proceedings.

Applying cost of service rules is costly and burdensome and unnecessary. Most reactive proceedings for generators in PJM are resolved in black box settlements that fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that, not surprisingly, produce a wide, unreasonable and discriminatory disparity among the rates per paid per MW-year.

Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and the recognition that capital costs are not distinguishable by function would increase prices in the capacity market. The VRR curve would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase. The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.

The NOI presents an opportunity to address the reactive issue using a market based approach. The best approach would be to issue a rule eliminating cost of service rates for reactive capability and allowing for recovery of capacity costs through existing markets, including a removal of any offset for reactive revenue in offers and in the capacity market demand (VRR) curve. A second

138 OATT Schedule 2.
139 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 93 (Aug. 31, 2020).
140 See *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000 (March 17, 2016) (Notice of Workshop).
141 177 FERC ¶ 61,118 (2021).

best approach would be to limit the revenue requirement that could be filed for under the OATT Schedule 2 to a level less than or equal to the reactive revenue credit included in the capacity market design, in the VRR curve net CONE value, currently $2,199 per MW-year.

As with all things in PJM markets, it is easy to focus on extreme complexity and lose sight of the big picture. The complexity includes power factors and power factor testing and convoluted and arbitrary allocation factors. The big picture here is that in PJM, the interrelated and self sustaining markets provide the opportunity for all power plants to recover all their costs, including a return on and of capital, including any identifiable reactive costs. There is no reason that part of those capacity costs should be paid directly in a non market, guaranteed, riskless revenue stream rather than in the market. The existence of the current option creates strong incentives for generators to maximize the allocation of capital costs to reactive in order to maximize guaranteed, nonmarket revenues.

The current process does not actually compensate resources based on their costs of investment in reactive power capability. The AEP Method assigns costs between real and reactive power based on a unit's power factor. This is effectively an allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

The AEP Method originated with a regulated utility assigning costs between two sources of regulated revenue requirement. The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue. Generation owners have an incentive to maximize such guaranteed revenue streams.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

The best and straightforward solution is to remove cost of service rates for reactive supply capability and to remove the offset. Investment in generation can and should be compensated entirely through markets. Removing cost of service rules would avoid the significant waste of resources incurred to develop unneeded cost of service rates.

The result would be to pay generators market based rates for both real and reactive capacity.

The PJM market design allows for the competitive investment in generation resources. The addition of separate rules allowing for the recovery of an arbitrarily defined portion of the same investment on a cost of service basis introduces a flaw into the competitive market design. The flaw is exacerbated when separate cost of service proceedings define the revenue requirement cost to supply reactive at values ranging from $13,044 to $964 per MW-year. (See Table 10-64)

The real issue is that the revenue requirement approach is inconsistent with both the theory and mechanics of PJM markets. The impact is to distort market outcomes.

The rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR Curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-year through inclusion in the Net CONE parameter of the capacity market demand (VRR) curve.[142] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve. In addition, market sellers, when submitting offers based on net avoidable costs must account for revenues received through cost of service reactive capability rates in the calculation.[143] Unit specific reactive capability rates up to that level are at least consistent with that parameter. Reactive capability rates either above or below that level distort capacity market outcomes. For example, a marginal resource with reactive revenue of $5,000 per MW-year reflected in their net ACR offer would suppress the capacity market clearing price. Conversely, a marginal resource with a reactive revenue of $1,000 per MW-year reflected in their net ACR offer would inflate the capacity market clearing price.

142 *See* OATT Attachment DD § 5.10(a)(v)(A).
143 OATT Attachment DD § 6.8(d).

Interconnection Requirements

A generating facility is not eligible for reactive payments when it is not connected directly to the PJM system and therefore does not provide reactive capability to PJM under Schedule 2, and should not receive payments for a service that it does not and cannot provide. In a number of cases now pending, the Market Monitor has challenged the eligibility of resources filing under OATT Schedule 2 because they are interconnected to facilities that PJM does not monitor and does not rely on to provide reactive capability.[144] The issue will be decided in a hearing currently pending at the FERC.[145]

The issue of eligibility is significant because the number of facilities interconnecting at points that are not on the PJM system is expected to increase. Such facilities do not contribute reactive capability to PJM, and based on anticipated power factor levels and the way the AEP method has been applied for calculating reactive rates under Schedule 2, such facilities would receive significantly larger payments per MW than the facilities that do provide reactive power capability useful to PJM.[146] These payments are for services not provided, but also would distort the PJM capacity market by paying a large share of the fixed costs of such facilities as reactive. This approach is a faulty and inefficient and noncompetitive market design.

Fleet Rates

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[147] Until the Commission took corrective action, fleet rates remained in place in PJM even when the actual units in the fleet changed as a result of unit retirements or sales of units.[148] New rules require unit owners to give notice of fleet changes in an informational filing or to file a new rate based on the remaining units, but do not yet require unit specific reactive rates.[149]

Fleet rates create confusion about what revenue is properly attributable to each unit in the fleet. Reactive rates should be stated separately for each unit, even if multiple plants or units are considered in a single proceeding. The MMU filed with the Commission to require unit specific rates when PJM proposed limited reforms that could have corrected the oversight and compliance problems posed by fleet rates.[150] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[151] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[152]

The MMU also raised issues related to fleet rates in a settlement establishing a fleet rate without specifying the actual portion of the fleet rate attributable to each unit in the fleet.[153] The approach could prevent or inhibit an appropriate adjustment of the fleet requirement if a unit receiving an unspecified portion of such requirement is deactivated or transferred because third parties without access to cost information would bear the burden of proof in a complaint proceeding.[154] The MMU also explained that the approach makes it impossible to calculate cost-based offers from such units in the PJM Capacity Market. The settlement was approved over the MMU's objection on the grounds that the tariff does not prohibit fleet rates.[155]

The MMU recommends that fleet rates be eliminated and that compensation be based on unit specific costs and rates and that rates be appropriately reduced when units with reactive payments retire.

Reactive Costs

In 2021, total reactive charges were $367.8 million, a 6.19 percent increase from the $346.0 million for 2020. Reactive capability charges increased from $346.0 million in 2020 to $367.0 million in 2021 and reactive service charges increased from $0.4 million in 2020 to $0.9 million in 2021. The $0.9 million for reactive service charges were paid to 24 units for operation in 377 unit hours.

Table 10-62 shows reactive service charges in 2020 and 2021, reactive capability charges and total charges.

144 See, e.g., FERC Docket Nos. ER21-2091, ER21-936, ER21-737, ER20-1863 & ER20-1851.
145 See Whitetail Solar 1, LLC, et al., Docket No. ER20-714-003, et al.
146 *See American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999).
147 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
148 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
149 *Id.*
150 151 FERC ¶ 61,224 at P 29 (2015).
151 OATT Schedule 2.
152 *Id.*
153 *See* Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
154 *Id.*
155 162 FERC ¶ 61,029 (2018).

Reactive service charges show charges to each zone for reactive service. Reactive capability charges show charges to each zone for reactive capability.

Table 10-62 Reactive service charges and reactive capability charges by zone: 2020 and 2021

	2020			2021		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$4,287,746	$4,287,746	$0	$4,289,651	$4,289,651
AEP	$4,797	$46,999,522	$47,004,319	$42,352	$49,221,441	$49,263,793
APS	$0	$17,913,000	$17,913,000	$0	$21,260,263	$21,260,263
ATSI	$0	$24,930,943	$24,930,943	$0	$25,305,857	$25,305,857
BGE	$0	$6,785,340	$6,785,340	$0	$6,635,411	$6,635,411
COMED	$0	$39,326,091	$39,326,091	$149,929	$40,923,979	$41,073,909
DAY	$0	$2,812,775	$2,812,775	$0	$2,814,025	$2,814,025
DUKE	$0	$9,528,512	$9,528,512	$0	$10,642,113	$10,642,113
DOM	$0	$37,363,934	$37,363,934	$0	$47,169,563	$47,169,563
DPL	$10,538	$10,261,586	$10,272,124	$1,517	$10,398,016	$10,399,534
DUQ	$0	$570,034	$570,034	$0	$570,288	$570,288
EKPC	$46,753	$2,177,752	$2,224,505	$1,231	$2,178,720	$2,179,951
JCPLC	$181,574	$7,423,374	$7,604,947	$0	$7,532,142	$7,532,142
MEC	$4,631	$6,126,496	$6,131,126	$8,696	$6,119,642	$6,128,338
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$20,955,918	$20,955,918	$0	$20,916,523	$20,916,523
PE	$0	$16,556,066	$16,556,066	$0	$17,353,604	$17,353,604
PEPCO	$0	$10,838,558	$10,838,558	$0	$9,873,217	$9,873,217
PPL	$180,337	$35,142,051	$35,322,388	$705,618	$36,819,187	$37,524,805
PSEG	$0	$27,839,542	$27,839,542	$0	$27,828,845	$27,828,845
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$18,124,076	$18,124,076	$0	$19,080,024	$19,080,024
Total	$428,629	$345,963,313	$346,391,943	$909,343	$366,932,512	$367,841,855

Table 10-63 shows the units which have received reactive service credits in 2021.

Table 10-63 Reactive service credits by plant (Total Dollars): 2021

2021		
Zone	Plant	Reactive Service Credits
AEP	AEP CEREDO 1 CT	$1,565
AEP	AEP CEREDO 4 CT	$1,340
AEP	AEP CLINCH RIVER 2 F	$18,677
AEP	AEP GARDEN CREEK - BUCHANAN CT 1-2	$886
AEP	AEP WOLF HILL 1 CT	$670
AEP	AEP WOLF HILL 2 CT	$6,837
AEP	AEP WOLF HILL 3 CT	$5,967
AEP	AEP WOLF HILL 4 CT	$6,087
AEP	AEP WOLF HILL 5 CT	$321
COMED	COM 935 KENDALL 1 CC	$30,166
COMED	COM 935 KENDALL 2 CC	$29,199
COMED	COM 935 KENDALL 3 CC	$31,899
COMED	COM 935 KENDALL 4 CC	$29,273
COMED	COM 942 NELSON 2 CC	$29,393
DPL	DPL BAYVIEW 2 D	$513
DPL	DPL BAYVIEW 3 D	$513
DPL	DPL BAYVIEW 5 D	$490
EKPC	EKPC COOPER 2 F	$1,231
METED	ME MOUNTAIN 1 CT	$8,696
PPL	PL HARWOOD 1-2 CT	$16,031
PPL	PL HAZELTON 1 CT	$65,744
PPL	PL HAZELTON 2 CT	$265,634
PPL	PL HAZELTON 3 CT	$197,731
PPL	PL HAZELTON 4 CT	$160,478
Total		$909,343

The table demonstrates the wide disparity in payments for reactive capability that result from the current cost of service rate case model settlement process.

Table 10-64 shows the settled reactive capability revenue requirements by technology effective on December 31, 2021.[156] The table demonstrates the wide disparity in payments for reactive capability that result from the current cost of service rate case model settlement process.

Table 10-64 Total settled reactive revenue requirements by unit type and fuel type: December 31, 2021

Unit Type	Fuel Type	Total Revenue Requirement per Year	MW	Number of Resources	Requirement per MW-year
CC	Gas	$128,050,591.74	50,346.2	158	$2,543.40
CT	Gas	$49,415,243.93	28,664.0	258	$1,723.95
CT	Oil	$4,870,245.73	3,640.5	137	$1,337.80
Diesel	Gas	$1,380,092.00	105.8	5	$13,044.35
Diesel	Oil	$1,028,792.65	168.3	36	$6,112.85
Diesel	Other - Gas	$940,634.85	122.5	13	$7,678.65
FC	Gas	$45,000.00	2.6	1	$17,307.69
Hydro	Water	$18,160,605.09	6,920.8	53	$2,624.06
Nuclear	Nuclear	$53,552,998.67	32,655.9	31	$1,639.92
Solar	Solar	$1,844,502.44	299.1	13	$6,166.84
Steam	Coal	$62,385,763.44	47,164.4	79	$1,322.73
Steam	Gas	$4,275,392.92	4,434.4	19	$964.14
Steam	Oil	$5,032,169.50	4,583.4	11	$1,097.91
Steam	Other - Solid	$340,000.00	34.0	2	$10,000.00
Steam	Wood	$207,759.31	153.0	3	$1,357.90
Wind	Wind	$19,590,962.81	4,681.6	36	$4,184.67
Total		$351,120,755.09	183,976.5	855	$1,908.51

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[157] Such equipment must include a governor or equivalent controls with the capability of operating at a maximum 5 percent droop and ±0.036 Hz deadband (or the equivalent or better).

PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[158]

The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides compensation for all capacity costs, including these, in the capacity market. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery.

156 The total amount in the final row of Table 10-30 is the amount that would be paid if the total rate effective on December 31, 2021 were effective for an entire year. The total rates effective on any given day depend on requests made by resource owners in filings to FERC and FERC approval of those rates.
157 157 FERC ¶ 61,122 (2016).
158 See 164 FERC ¶ 61,224 (2018).

Frequency Control Definition

There are four distinct types of frequency control, distinguished by response timeframe and operational nature: Inertial Response, Primary Frequency Response, Secondary Frequency Control, and Tertiary Frequency Control.

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to change in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.
- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins taking effect within 10 to 15 seconds and can maintain itself for several minutes up to an hour in some cases. It is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is available in PJM as Primary Reserve. It is initiated by an all call from the PJM control center.

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) is a combination of agreements among the entities in the VACAR subregion including Dominion.[159] VACAR is a subregion of the SERC Reliability Corporation (SERC) region. The agreement remained in effect in 2020. The agreement requires that each entity maintain primary reserves to meet the VACAR contingency reserve commitment (VACAR reserves) and deploy such reserves in the case of an emergency (e.g. loss of a unit in VACAR).[160] Dominion is the only party to the VRSA that is also a transmission owner and a generation owner in PJM. The VRSA is not a public agreement. PJM is not a party to the VRSA. However, as the reliability coordinator for Dominion Virginia Power, PJM is responsible for scheduling Dominion's required reserves in the SERC region as described in the PJM manuals.[161]

PJM procures synchronized reserves and primary reserves for the PJM region, including Dominion. The synchronized reserve and primary reserve requirements are equal to the largest single contingency and 150 percent of the largest contingency. The requirement is procured separately for the RTO and the MidAtlanic Dominion area (MAD) when the largest contingency is located outside of MAD. All units in PJM that meet the synchronized or primary reserve operating parameter requirements are eligible to meet the synchronized and primary requirements as long as PJM does not deselect them.

PJM procures Day-Ahead Scheduling Reserves (DASR) for the PJM region, including Dominion, as Secondary Reserves. The DASR requirement is calculated daily and is equal to the peak load forecast for the ReliabilityFirst region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error, plus Dominion's share of the VACAR contingency reserve commitment. All units in PJM that meet the DASR operating parameter requirements are eligible to meet the DASR requirement.[162] There is no requirement that a specific amount of DASR be located in Dominion. Equation 10-1 shows the DASR requirement calculation.[163]

159 VRSA entities: Dominion, Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.

160 *See* SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.

161 See PJM. "Manual 13: Emergency Operations," Rev. 78 (Jan. 27, 2021).

162 DASR can be provided by units that do not clear the Day-Ahead Energy Market and can start within 30 minutes or by units that clear the Day-Ahead Energy Market and can ramp up within 30 minutes.

163 During cold weather alerts and hot weather alerts, the DASR requirement is increased to procure additional reserves.

Equation 10-1: DASR Requirement Formula

$$\text{DASR Requirement} = (\text{RFC and EKPC Peak}) \times (\text{FOR} + \text{LFE}) + \text{DOM VACAR}$$

Issues

PJM is expected to implement the reserve market changes in October 2022. These changes include the consolidation of synchronized reserves tier 1 and tier 2 and the reserve must offer requirement. With these changes, it will not be possible for Dominion to hold reserves to meet its obligations under the VRSA without failing the must offer requirement in PJM. Under the reserve market changes, it will not be possible for Dominion to meet both the VRSA and the PJM reserve rules.

Recommendations

The Market Monitor recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA.

The Market Monitor recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas.

Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution. CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (There can be multiple binding transmission constraints.) CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[4] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the single higher price for all the energy used, including energy from low cost and energy from high cost generation, while generators are each paid the price at their individual bus. Congestion is the difference between what load pays based on the single higher price at load buses and what generators receive based on the lower prices at the individual generator buses due to binding transmission constraints.

1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.
2 The difference in losses is not part of congestion.
3 PJM billing examples can be found in *2021 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
4 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

The energy, marginal losses and congestion metrics must be interpreted carefully.

In PJM accounting, the term total congestion refers to net implicit CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

As with congestion, total system energy costs are more precisely termed net system energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[5]

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP.

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. For a given market solution, a change in the elected reference bus does not change the LMP at any bus and does not change total congestion paid by load and does not change the local congestion paid by load at a specific location. Holding aside the marginal loss component of LMP, local congestion is the sum of the total LMP charges to load at the defined set of buses minus the sum of the total LMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location. Local congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. PJM's fast start pricing logic results in pricing run locational marginal prices (PLMP). PLMP is the price that load pays and generators receive in the PJM energy market.

While PLMP is the official settlement price, PJM continues to calculate LMP based on the logic that PJM uses to actually dispatch system resources and used prior to the introduction of fast start to consistently define dispatch and prices. The LMPs from the dispatch run are dispatch run locational marginal prices (DLMP). While the settlement prices are PLMP, settlement MW are based on the dispatch run in the day-ahead market and are metered output in the real-time market.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $466.6 million or 88.2 percent, from $528.7 million in 2020 to $995.3 million in 2021.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $563.7 million or 85.1 percent, from $662.5 million in 2020 to $1,226.2 million in 2021.
- **Balancing Congestion.** Negative balancing congestion costs increased by $97.1 million, from -$133.8 million in 2020 to -$230.9 million in 2021. Negative balancing explicit charges increased by $23.1 million, from -$77.6 million in 2020 to -$100.7 million in 2021.
- **Real-Time Congestion.** Real-time congestion costs increased by $706.7 million, from $749.3 million in 2020 to $1,456.0 million in 2021.
- **Monthly Congestion.** Monthly total congestion costs in 2021 ranged from $29.1 million in January to $175.3 million in November.

5 The total congestion and marginal losses for 2021 were calculated as of January 10, 2022, and are subject to change, based on continued PJM billing updates.

- **Geographic Differences in CLMP.** Differences in CLMP among eastern control zones in PJM were primarily a result of binding on the Three Mile Island Transformer, the Nottingham Series Reactor, the Cumberland - Juniata Line, the Conastone Transformer, and the Brighton Circuit Breaker.

- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in 2021. The number of congestion event hours in the day-ahead energy market was about twice the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency decreased by 27.9 percent from 78,239 congestion event hours in 2020 to 56,425 congestion event hours in 2021.

  Real-time congestion frequency increased by 4.9 percent from 21,984 congestion event hours in 2020 to 23,068 congestion event hours in 2021.

- **Congested Facilities.** The monthly average of daily day-ahead congestion event hours decreased in November 2020 as a result of decreased UTC activity due to a FERC order issued effective November 1, 2020, directing PJM to charge uplift to up to congestion transactions.[6] Day-ahead, congestion event hours decreased on all types of facilities except flowgates.

  The Three Mile Island Transformer was the largest contributor to congestion costs in 2021. With $88.2 million in total congestion costs, it accounted for 8.9 percent of the total PJM congestion costs in 2021.

- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. CT Price Setting Logic caused -$0.3 million of day-ahead congestion in 2021 and -$6.0 million of balancing congestion in 2021. While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals. None of the closed loop interfaces were binding in 2021 or 2020.

- **Zonal Congestion.** AEP had the highest zonal congestion costs among all control zones in 2021. AEP had $163.1 million in zonal congestion costs, comprised of $198.2 million in day-ahead congestion costs and -$35.1 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $476.3 million or 99.5 percent, from $478.5 million in 2020 to $954.8 million in 2021. The loss MWh in PJM increased by 953.8 GWh or 6.7 percent, from 14,317.2 GWh in 2020 to 15,271.0 GWh in 2021. The loss component of real-time LMP in 2021 was $0.02, compared to $0.01 in 2020.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $461.6 million or 87.7 percent, from $526.3 million in 2020 to $987.9 million in 2021.

- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $14.7 million or 30.7 percent, from -$47.7 million in 2020 to -$33.1 million in 2021.

- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $170.8 million or 107.1 percent, from $159.6 million in 2020, to $330.4 million in 2021.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2021 ranged from $42.5 million in April to $112.8 million in August.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $305.8 million or 96.4 percent, from -$317.4 million in 2020 to -$623.2 million in 2021.

- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $276.8 million or 68.9 percent, from -$401.4 million in 2020 to -$678.2 million in 2021.

- **Balancing System Energy Costs.** Balancing system energy costs decreased by $29.3 million or 35.9 percent, from $81.6 million in 2020 to $52.3 million in 2021.

- **Monthly Total System Energy Costs.** Monthly total system energy costs in 2021 ranged from -$77.3 million in November to -$28.4 million in April.

6 172 FERC ¶ 61,046 (2020).

Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion costs increased by $466.6 million or 88.2 percent, from $528.7 million in 2020 to $995.3 million in 2021.

The monthly total congestion costs ranged from $29.1 million in January to $175.3 million in November in 2021.

The implementation of fast start pricing caused day-ahead congestion to increase by $1.3 million and caused negative balancing congestion to increase by $2.8 million over the September through December, 2021 period.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all congestion revenues. The congestion offset for the first seven months of the 2021/2022 planning period was 44.8 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first seven months of the 2021/2022 planning period, using the rules effective for each planning period, was 72.2 percent. Load has been underpaid by $2.7 billion from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period.

Issues

Closed Loop Interfaces and CT Pricing Logic

PJM uses closed loop interfaces and CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM used CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM's LMP security constrained pricing logic. The purpose of forcing inflexible units to be marginal is to reduce the uplift associated with the dispatch of inflexible resources. PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021.

Through the assumption of artificial flexibility of the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of CT pricing logic forced the affected resource bus LMP to match the marginal offer of the resource. PJM adjusts the constraint limit based on the output of the resource. Sometimes the constraint limit does not match the flows on the constraint, and the constraint violates instead of binding, resulting in prices set by the transmission constraint penalty factor. In the case of a closed loop interface, all buses within the interface were modeled with a distribution factor (dfax) of 1.0 to the constraint and therefore with the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affected the CLMP of constrained side buses in proportion to their dfax to that constraint.[7] One objective of making inflexible resources marginal was to artificially minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of closed loop interfaces and CT pricing logic was a source of modeling differences between the day-ahead and real-time markets. When closed loop interfaces and CT pricing logic were not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model resulted in positive or negative balancing congestion.

Failure to model the same constraints in the day-ahead and real-time markets results in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion.

Use of closed loop interfaces and CT price setting logic required manipulation of the economic dispatch model.

7 The constrained side means the higher priced side with a positive CLMP created by the constraint.

Closed loop interfaces and CT price setting logic, like fast start pricing logic that replaced it, force higher cost inflexible units to be marginal.

While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM used a related logic to force inflexible units to be on the margin in both real time and day ahead. Like closed loop interfaces and CT pricing logic, the artificially enforced constraint results in negative congestion. As a result, more power is produced in the artificial closed loop or constrained area than would result without the artificial constraint. This means that there are more generation credits than load charges in the constrained area. The constrained area exports power, the lower cost generators outside the constrained area are backed down and prices are lower outside the constrained area as a result. All of the generation within the artificially constrained area is paid the higher CLMP, but only a smaller amount of load (in some cases no load) in the constrained area pays this higher CLMP. As a result, load pays less than generation receives in the artificially constrained area. This difference is negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing charges.

Balancing Congestion Cost Calculation Logic Change

Effective April 1, 2018, PJM made a significant change to the calculation and allocation of balancing congestion costs.[8]

Prior to April 1, 2018, balancing implicit CLMP charges calculated at the zonal and aggregate level were determined by bus specific deviations between day-ahead and real-time MWh priced at the bus specific congestion price in the real-time energy market.

As of April 1, 2018, at the time of the introduction of five minute settlements, PJM modified the calculation so that zonal and aggregate balancing implicit CLMP charges are determined by netting the bus specific hourly deviations across every bus in a zone or subzonal aggregate and pricing the resulting deviation in zonal or aggregate total deviations at the zonal or aggregate congestion price in the real-time energy market. As a result, the allocation of balancing implicit congestion was reduced for MW deviations associated with load and virtual bids that settle at zones and aggregates.

Another result of the change in rules was to increase negative balancing charges billed to load on a load ratio basis. While total load deviations and associated balancing charges at load aggregates were reduced by netting, the rules for determining balancing CLMP credits and charges to all other balancing MW deviations at all other bus or aggregates did not change. This means that the change in rules resulted in a decrease in total balancing implicit charges while having no effect on the calculation of total balancing implicit credits. The net result has been an increase in negative balancing congestion costs, which is the difference between balancing CLMP charges from deviations at aggregates and zones (reduced due to the rule change) and bus specific balancing CLMP credits (not affected by the rule change). This has caused an increase in total negative balancing charges.

The netting of zonal and aggregate deviations decreased the allocation of balancing charges to load deviations and increased total negative balancing congestion. Negative balancing congestion is assigned to load and exports on a load ratio share basis as the result of a FERC order.

Table 11-1 shows the actual total balancing implicit CLMP charges for each year from 2018 through 2021 based on the methods in place at the time. Table 11-1 shows that the April 1, 2018, settlement rule caused negative balancing congestion costs to increase for each year from 2018 through 2021. Table 11-1 shows that the April 1, 2018, settlement rule caused negative total balancing implicit charges to increase by $15.2 million (13.2 percent) in 2021 and caused negative total balancing implicit charges to increase $41.8 million in total from April 1, 2018 through December 31, 2021.[9]

8 See PJM, "Manual 28: Operating Agreement Accounting," Rev. 84 (Dec.17, 2020).

9 The total number cannot be seen in table because it includes only the April through December period in 2018.

Table 11-1 Total balancing implicit CLMP charge (Dollars (Millions)) (old method and new method): 2018 through 2021

	Balancing Implicit CLMP Charges ($ Million)									
	Old Method			New Method			Method Used			
	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Change Between New and Old
2018	$18.9	$62.8	($43.9)	$0.1	$59.7	($59.6)	$11.5	$62.0	($50.5)	($15.6)
2019	$17.9	$53.8	($35.8)	$3.7	$51.1	($47.4)	$3.7	$51.1	($47.4)	($11.5)
2020	($4.2)	$43.6	($47.8)	($15.1)	$41.3	($56.3)	($14.7)	$41.5	($56.2)	($8.6)
2021	($4.4)	$110.7	($115.1)	($20.3)	$110.0	($130.2)	($20.3)	$110.0	($130.2)	($15.2)

The differences in results between the old method and the new method result from the use of zonal CLMP and zonal net deviations in place of the use of bus specific CLMPs and bus specific deviations.

When the total day-ahead factor weighted real-time bus CLMP is lower than real-time zonal CLMP, the balancing implicit CLMP charges will be lower using the new method. When the total day-ahead factor weighted real-time bus CLMP is higher than real-time zonal CLMP, the balancing implicit CLMP charges will be higher using the new method. Table 11-2 presents three cases to explain the calculation. The day-ahead load factor or real-time load factor for an aggregate equals the load at each bus divided by the total aggregate load.

Case 1 (Table 11-2) shows the case in which the total day-ahead factor weighted real-time bus CLMP ($1.1) is less than the real-time zonal CLMP ($1.6). The total balancing implicit CLMP charges using the new method (-$4.2) are lower than under the old method ($1.8).

Case 2 (Table 11-2) shows the case in which the total day-ahead factor weighted real-time bus CLMP ($1.9) is larger than the real-time zonal CLMP ($1.5). The total balancing implicit CLMP charges using the new method ($2.0) are higher than under the old method (-$1.2).

Case 3 (Table 11-2) shows that the total day-ahead factor weighted real-time bus CLMP ($1.6) is equal to the real-time zonal CLMP ($1.6). The total balancing implicit CLMP charges using the new method (-$4.2) are equal under the old method (-$4.2).

Table 11-2 Example of balancing implicit CLMP charge calculation (old method and new method)

									Balancing Implicit Withdrawal Charges	
Case 1	Real-Time CLMP	Real-Time Load	Real-Time Load Factor	Real-Time CLMP * Real-Time Load Factor	Day-Ahead Load Factor	Real-Time CLMP * Day-Ahead Load Factor	Day-Ahead Load	Balancing Load	Old Method	New Method
Bus A	$1.0	4.0	0.4	$0.4	0.9	$0.9	10.8	(6.8)	($6.80)	
Bus B	$2.0	6.0	0.6	$1.2	0.1	$0.2	1.2	4.8	$9.60	
Zonal		10.0		$1.6		$1.1	12.0		$2.8	($3.20)
Balancing Implicit Injection Credits									$1.0	$1.0
Balancing Implicit Congestion Charges									$1.8	($4.2)
Case 2										
Bus A	$1.0	5.0	0.5	$0.5	0.1	$0.1	0.8	4.2	$4.20	
Bus B	$2.0	5.0	0.5	$1.0	0.9	$1.8	7.2	(2.2)	($4.40)	
Zonal		10.0		$1.5		$1.9	8.0		($0.2)	$3.00
Balancing Implicit Injection Credits									$1.0	$1.0
Balancing Implicit Congestion Charges									($1.2)	$2.0
Case 3										
Bus A	$1.0	4.0	0.4	$0.4	0.4	$0.4	4.8	(0.8)	($0.80)	
Bus B	$2.0	6.0	0.6	$1.2	0.6	$1.2	7.2	(1.2)	($2.40)	
Zonal		10.0		$1.6		$1.6	12.0		($3.2)	($3.20)
Balancing Implicit Injection Credits									$1.0	$1.0
Balancing Implicit Congestion Charges									($4.2)	($4.2)

Locational Marginal Price (LMP)

Components

On June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While the use of a single node reference bus or a distributed load reference bus has no effect on the total LMP, the use of a single node reference bus or a distributed load reference bus does affect the components of LMP. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. No congestion component is normally included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of system energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[10] The first derivative of total losses with respect to the power flow is marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[11] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to meet the load in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-3 shows the PJM real-time load-weighted average LMP components for 2008 through 2021.[12]

The real-time load-weighted average LMP increased by $18.02 or 82.8 percent from $21.77 in 2020 to $39.78 in 2021. The real-time load-weighted average congestion component was $0.04 in 2021, compared to $0.02 in 2020. The real-time load-weighted, average loss component in 2021 was $0.02, compared to $0.01 in 2020. The real-time load-weighted average system energy component increased by $18.00 or 82.8 percent from $21.73 in 2020 to $39.72 in 2021. Using a load-weighted reference bus, the real-time load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss components used in real-time settlement are not zero, although these components are not fully accurate.

10 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

11 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

12 The PJM real-time load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the real-time energy market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the real-time energy market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM wide real-time load-weighted, average LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

Table 11-3 Real-time load-weighted average LMP components (Dollars per MWh): 2008 through 2021[13]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02
2014	$53.14	$53.13	($0.02)	$0.02
2015	$36.16	$36.11	$0.04	$0.02
2016	$29.23	$29.18	$0.04	$0.01
2017	$30.99	$30.96	$0.02	$0.01
2018	$38.24	$38.19	$0.04	$0.02
2019	$27.32	$27.28	$0.02	$0.02
2020	$21.77	$21.73	$0.02	$0.01
2021	$39.78	$39.72	$0.04	$0.02

Table 11-4 shows the PJM day-ahead, load-weighted, average LMP components for 2008 through 2021.[14] The day-ahead load-weighted average LMP increased by $17.97, or 84.0 percent, from $21.40 in 2020 to $39.37 in 2021. The day-ahead load-weighted average congestion component increased by $0.03 from $0.07 in 2020 to $0.10 in 2021. The day-ahead load-weighted average loss component was $0.02 in 2021, compared to -$0.00 in 2020. The day-ahead load-weighted average energy component increased by $17.91, or 83.9 percent, from $21.34 in 2020 to $39.25 in 2021. Using a load-weighted reference bus, the day-ahead, load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

Table 11-4 Day-ahead load-weighted average LMP components (Dollars per MWh): 2008 through 2021

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00
2014	$53.62	$53.38	$0.26	($0.02)
2015	$36.73	$36.51	$0.24	($0.01)
2016	$29.68	$29.55	$0.14	($0.01)
2017	$30.85	$30.81	$0.05	($0.02)
2018	$37.97	$37.83	$0.16	($0.01)
2019	$27.23	$27.17	$0.08	($0.01)
2020	$21.40	$21.34	$0.07	($0.00)
2021	$39.37	$39.25	$0.10	$0.02

Table 11-5 shows the PJM real-time load-weighted average LMP by constrained and unconstrained hours.

Table 11-5 Real-time load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): 2020 and 2021

	2020		2021	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$22.30	$15.73	$25.96	$21.31
Feb	$19.56	$17.12	$45.23	$23.19
Mar	$18.28	$16.13	$26.57	$19.67
Apr	$17.63	$17.39	$26.93	$21.82
May	$18.81	$12.20	$30.74	$22.46
Jun	$21.64	$14.18	$35.33	$26.34
Jul	$28.58	$15.77	$42.25	$28.29
Aug	$26.01	$17.43	$53.08	$30.84
Sep	$19.94	$12.31	$52.26	$34.37
Oct	$22.19	$22.78	$59.05	$37.60
Nov	$20.86	$26.31	$62.98	$65.82
Dec	$27.28	$21.27	$39.32	$31.41
Avg	$22.29	$17.59	$41.73	$27.52

13 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

14 In the real-time energy market, the energy component (SMP) equals the system load-weighted price, with the caveat about state-estimated versus metered load. However, in the day-ahead energy market the day-ahead energy component of LMP (SMP) and the PJM day-ahead, load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead, load-weighted LMP is a result of the difference in the types of load used to weight the load-weighted reference bus and the load-weighted LMP. In the day-ahead energy market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead SMP is, therefore, a system fixed demand weighted price. The day-ahead, load-weighted LMP calculation uses all types of demand, including fixed, price-sensitive and decrement bids.

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-6 for 2020 and 2021. In 2021, BGE had the highest real-time congestion component of all control zones, $4.79, and ACEC had the lowest real-time congestion component, -$6.35.

Table 11-6 Zonal real-time load-weighted average LMP components (Dollars per MWh): 2020 and 2021

	2020				2021			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
ACEC	$19.72	$22.04	($2.36)	$0.05	$34.13	$40.20	($6.35)	$0.28
AEP	$22.14	$21.60	$0.45	$0.09	$40.31	$39.50	$0.83	($0.02)
APS	$22.40	$21.64	$0.82	($0.06)	$40.44	$39.52	$0.94	($0.03)
ATSI	$22.55	$21.67	$0.58	$0.30	$39.47	$39.66	($0.36)	$0.17
BGE	$25.78	$21.89	$3.30	$0.59	$45.77	$39.92	$4.79	$1.07
COMED	$20.18	$21.70	($1.08)	($0.44)	$37.00	$39.81	($1.69)	($1.13)
DAY	$23.23	$21.76	$0.49	$0.98	$42.92	$39.89	$1.51	$1.51
DOM	$23.05	$21.77	$1.23	$0.05	$44.67	$39.78	$4.34	$0.55
DPL	$22.90	$21.94	$0.65	$0.30	$40.24	$39.88	($0.31)	$0.67
DUKE	$22.37	$21.72	$0.51	$0.14	$41.49	$39.84	$1.61	$0.04
DUQ	$22.79	$21.75	$1.18	($0.15)	$39.17	$39.70	($0.04)	($0.49)
EKPC	$22.14	$21.79	$0.31	$0.04	$41.20	$39.93	$1.35	($0.07)
JCPLC	$20.05	$22.13	($2.12)	$0.04	$34.52	$40.27	($5.96)	$0.21
MEC	$21.16	$21.74	($0.40)	($0.18)	$39.97	$39.69	$0.44	($0.16)
OVEC	$20.75	$20.78	$0.32	($0.34)	$37.98	$38.08	$0.74	($0.84)
PE	$20.84	$21.50	($0.52)	($0.14)	$37.73	$39.39	($1.38)	($0.27)
PECO	$19.29	$21.78	($2.25)	($0.23)	$33.55	$39.73	($5.92)	($0.25)
PEPCO	$23.59	$21.85	$1.47	$0.28	$44.62	$39.95	$3.96	$0.72
PPL	$19.42	$21.65	($1.85)	($0.39)	$35.92	$39.47	($3.00)	($0.55)
PSEG	$19.69	$21.77	($2.03)	($0.04)	$35.78	$39.81	($4.17)	$0.14
REC	$20.74	$22.16	($1.45)	$0.03	$38.80	$40.28	($1.71)	$0.23
PJM	$21.77	$21.73	$0.02	$0.01	$39.78	$39.72	$0.04	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-7 for 2020 and 2021. In 2021, BGE had the highest day-ahead congestion component of all control zones, $5.00, and ACEC had the lowest day-ahead congestion component, -$5.86.

Table 11-7 Zonal day-ahead load-weighted average LMP components (Dollars per MWh): 2020 and 2021

	2020				2021			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
ACEC	$19.18	$21.60	($2.40)	($0.02)	$33.90	$39.67	($5.86)	$0.10
AEP	$21.89	$21.25	$0.57	$0.07	$39.93	$39.11	$0.83	($0.01)
APS	$21.96	$21.29	$0.71	($0.04)	$40.05	$39.03	$1.01	$0.00
ATSI	$21.91	$21.25	$0.43	$0.23	$39.56	$39.02	$0.30	$0.23
BGE	$25.36	$21.48	$3.31	$0.57	$45.51	$39.46	$5.00	$1.05
COMED	$20.01	$21.24	($0.86)	($0.38)	$36.49	$39.16	($1.71)	($0.96)
DAY	$23.19	$21.38	$0.81	$1.00	$42.69	$39.45	$1.58	$1.67
DOM	$22.89	$21.37	$1.48	$0.04	$43.66	$39.39	$3.80	$0.47
DPL	$21.47	$21.63	($0.45)	$0.29	$39.43	$39.62	($0.87)	$0.67
DUKE	$22.50	$21.36	$0.94	$0.19	$41.42	$39.22	$1.98	$0.22
DUQ	$22.27	$21.37	$1.02	($0.12)	$39.21	$39.20	$0.47	($0.46)
EKPC	$22.17	$21.62	$0.62	($0.08)	$40.90	$39.76	$1.45	($0.31)
JCPLC	$19.23	$21.64	($2.38)	($0.03)	$34.52	$39.62	($5.15)	$0.05
MEC	$20.23	$21.38	($0.89)	($0.25)	$39.66	$39.33	$0.61	($0.28)
OVEC	$21.12	$20.78	$0.68	($0.35)	$40.95	$41.44	$0.34	($0.83)
PE	$21.13	$21.49	($0.36)	($0.01)	$38.93	$39.44	($0.51)	($0.01)
PECO	$18.75	$21.34	($2.29)	($0.30)	$33.24	$39.15	($5.50)	($0.41)
PEPCO	$23.55	$21.56	$1.66	$0.33	$44.05	$39.64	$3.59	$0.82
PPL	$18.82	$21.24	($1.94)	($0.48)	$35.73	$38.91	($2.42)	($0.77)
PSEG	$19.18	$21.36	($2.11)	($0.08)	$34.91	$39.28	($4.40)	$0.04
REC	$20.22	$21.87	($1.66)	$0.01	$38.00	$39.62	($1.77)	$0.15
PJM	$21.40	$21.34	$0.07	($0.00)	$39.37	$39.25	$0.10	$0.02

Hub Components

The real-time components of LMP for each hub are presented in Table 11-8 for 2020 and 2021.[15]

Table 11-8 Hub real-time average LMP components (Dollars per MWh): 2020 and 2021

	2020				2021			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$20.38	$20.63	$0.19	($0.44)	$37.44	$38.12	$0.36	($1.04)
AEP-DAY Hub	$21.17	$20.63	$0.47	$0.07	$38.63	$38.12	$0.63	($0.12)
ATSI Gen Hub	$20.91	$20.63	$0.33	($0.04)	$37.20	$38.12	($0.41)	($0.51)
Chicago Gen Hub	$18.72	$20.63	($1.23)	($0.67)	$34.31	$38.12	($2.25)	($1.57)
Chicago Hub	$19.12	$20.63	($1.12)	($0.38)	$35.21	$38.12	($1.90)	($1.02)
Dominion Hub	$21.39	$20.62	$0.89	($0.13)	$41.47	$38.12	$3.17	$0.18
Eastern Hub	$20.40	$20.63	($0.42)	$0.20	$37.20	$38.12	($1.45)	$0.52
N Illinois Hub	$19.02	$20.63	($1.11)	($0.49)	$34.96	$38.12	($1.94)	($1.23)
New Jersey Hub	$18.63	$20.63	($1.93)	($0.07)	$33.20	$38.12	($4.98)	$0.06
Ohio Hub	$21.22	$20.63	$0.47	$0.13	$38.60	$38.12	$0.54	($0.06)
West Interface Hub	$20.93	$20.63	$0.48	($0.18)	$38.61	$38.12	$0.94	($0.46)
Western Hub	$20.92	$20.63	$0.41	($0.11)	$38.88	$38.12	$0.89	($0.14)

The day-ahead components of LMP for each hub are presented in Table 11-9 for 2020 and 2021.

Table 11-9 Hub day-ahead average LMP components (Dollars per MWh): 2020 and 2021

	2020				2021			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$20.24	$20.29	$0.35	($0.40)	$37.39	$37.69	$0.66	($0.96)
AEP-DAY Hub	$20.96	$20.29	$0.59	$0.08	$38.35	$37.69	$0.71	($0.05)
ATSI Gen Hub	$20.63	$20.29	$0.38	($0.04)	$37.62	$37.69	$0.26	($0.33)
Chicago Gen Hub	$18.62	$20.29	($1.07)	($0.60)	$34.22	$37.69	($2.10)	($1.37)
Chicago Hub	$19.06	$20.29	($0.92)	($0.31)	$34.96	$37.69	($1.89)	($0.85)
Dominion Hub	$21.13	$20.29	$1.01	($0.17)	$40.27	$37.69	$2.51	$0.07
Eastern Hub	$19.49	$20.29	($0.99)	$0.18	$36.28	$37.69	($1.94)	$0.52
N Illinois Hub	$18.93	$20.29	($0.92)	($0.44)	$34.71	$37.69	($1.91)	($1.07)
New Jersey Hub	$18.14	$20.29	($2.06)	($0.10)	$32.85	$37.69	($4.78)	($0.06)
Ohio Hub	$20.97	$20.29	$0.57	$0.10	$38.32	$37.69	$0.63	($0.00)
West Interface Hub	$20.74	$20.29	$0.62	($0.17)	$38.50	$37.69	$1.19	($0.38)
Western Hub	$20.95	$20.29	$0.66	($0.01)	$38.92	$37.69	$1.22	$0.00

Congestion

Congestion Accounting

In PJM accounting, total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are not directly attributable to specific participants that are distributed on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference

15 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time, load-weighted, average of the hourly components of LMP.

bus does not change the LMPs or the difference between LMPs for a given market solution or actual congestion, it merely changes the components of the LMP.

Congestion occurs in the day-ahead and real-time energy markets.[16] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the real-time energy market.

Implicit CLMP charges are the CLMP charges calculated for energy injected or withdrawn at a location. The explicit CLMP charges are the CLMP charges calculated for transactions with a defined source and a sink. For example, implicit CLMP charges are calculated for network load and explicit CLMP charges are calculated for up to congestion transactions (UTCs). Inadvertent CLMP charges are CLMP charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour.

CLMP charges and CLMP credits are calculated for both the day-ahead and balancing energy markets.

- Day-Ahead Implicit Load CLMP Charges. Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction.
- Day-Ahead Implicit Generation CLMP Credits. Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.[17] Day-ahead implicit injection credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction.
- Balancing Implicit Load CLMP Charges. Balancing implicit withdrawal charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- Balancing Implicit Generation CLMP Credits. Balancing implicit injection credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- Explicit CLMP Charges. Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- Inadvertent CLMP Charges. Inadvertent CLMP charges are charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[18]

16 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term congestion costs as used here.

17 Internal bilateral transactions are included in the tariff definitions of Market Participant Energy Injections and Market Participant Energy Withdrawals. The purchase part of an internal bilateral transaction is an injection to the buyer and the sale part of an internal bilateral transaction is a withdrawal to the seller. The tariff (Attachment K) also says market participants will be charged implicit CLMP charges for all Market Participant Energy Withdrawals and will be credited implicit CLMP credits for all Market Participant Energy Injections. The seller of an internal bilateral transaction will be charged implicit CLMP charges at the source and the buyer of an internal bilateral transaction will be credited implicit CLMP credits at the sink. Internal bilateral transaction CLMP credits and charges sum to zero, as the IBT is merely a transfer of ownership injection and withdrawal MW and associated charges and credits between participants, meaning that the sum of all MW and all credits and all charges with and without IBTs are the same.

18 PJM Operating Agreement Schedule 1 §3.7.

The congestion accounting calculation equations are in Table 11-10.

Table 11-10 Congestion accounting calculations

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs
MWh Category	**Definition**
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh

PJM billing items include Day-Ahead Transmission Congestion Charges, Day-Ahead Transmission Congestion Credits, Balancing Transmission Congestion Charges, and Balancing Transmission Congestion Credits. Those line items are calculated for each PJM member. The congestion bill shows the CLMP charges or credits collected from the PJM market participants. However, the sum of an individual customer's CLMP credits or charges on the customer's bill is not a measure of the congestion paid by that customer.

The congestion paid by a customer is the difference between what the customer paid for energy and what all network sources of that energy were paid to serve that customer. A load customer's congestion bill, in contrast, merely indicates whether the LMP they paid for their withdrawals is higher or lower than the system energy price due to transmission constraints. The customer's bill is correct, but the bill does not measure congestion paid by the customer, only how much the customer was charged and credited for their MW positions. The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in CLMP charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation. Congestion costs can be both positive and negative and CLMP charges and CLMP credits can be both positive and negative. CLMP charges, positive or negative, are paid by withdrawals and CLMP credits, positive or negative, are paid to injections. Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when negative, measure the net congestion credit paid to a participant group. Explicit CLMP charges, when positive, measure the congestion payment to a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs).

The congestion accounting definitions can be misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means only that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

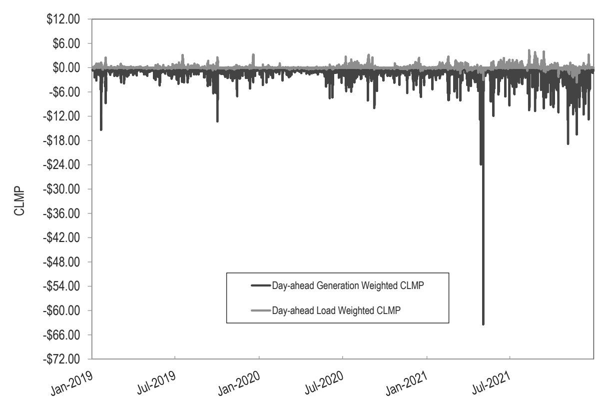
The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor from the constraint to the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[19]

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. At the load-weighted reference bus, which represents the load center of the system, the LMP includes no congestion or loss components, by definition. The load weighted, average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related CLMP charges is logically zero and the small reported differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP, due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP, due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. Due to transmission constraints, the average generation weighted CLMP for generation resources is lower than the LMP at the load-weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation CLMP credits are negative.

Figure 11-1 shows the weighted average CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that in 2019 through 2021, day-ahead generation weighted CLMPs were generally negative and day-ahead, load weighted CLMPs were generally positive, indicating that load was charged a higher weighted average LMP for energy as a result of transmission constraints than the weighted average LMP generation was paid to provide that energy. This means that total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-13 and Table 11-14). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

The day-ahead, generation weighted CLMPs were significantly negative for two hours on May 4, 2021 due to high shadow prices of two constraints caused by a transmission outage in the DOM Zone.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: 2019 through 2021



Total Congestion

Total congestion costs in PJM in 2021 were $995.3 million, comprised of implicit withdrawal charges of $391.6 million, implicit injection credits of -$637.1 million, and explicit charges of -$33.4 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy, due to binding transmission constraints.

Table 11-11 shows total congestion for 2008 through 2021. Total congestion costs in Table 11-11 include

19 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[20 21]

Table 11-11 Total congestion costs (Dollars (Millions)): 2008 through 2021[22]

	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,300	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,770	4.1%
2011	$999	(29.8%)	$35,890	2.8%
2012	$529	(47.0%)	$29,180	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%
2019	$583	(55.5%)	$41,680	1.4%
2020	$529	(9.4%)	$36,280	1.5%
2021	$995	88.2%	$54,130	1.8%

CLMP charges and credits are not congestion. CLMP charges and credits reflect marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Table 11-12 shows total congestion by day-ahead and balancing component for 2008 through 2021.

Table 11-12 Total CLMP credits and charges by accounting category (Dollars (Millions)): 2008 through 2021

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3
2016	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	($0.0)	$1,023.7
2017	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6
2018	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9
2019	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$0.0	$583.3
2020	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.5	($77.6)	($133.8)	$0.0	$528.7
2021	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$0.0	$995.3

20 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

21 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

22 In Table 11-11, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Charges and Credits versus Congestion: Virtual Transactions, Load and Generation

In PJM's two settlement system, there is a day-ahead market and a real-time, balancing market, that make up a market day.

In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtual bids, physical load and generation have net MW at the close of a market day's day-ahead and balancing settlement.

Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day. Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion.

Table 11-13 and Table 11-14 show the total CLMP charges and credits for each transaction type in 2021 and 2020. Table 11-13 shows that in 2021 DECs paid $24.6 million in CLMP charges in the day-ahead market, were paid $55.0 million in CLMP credits in the balancing energy market, resulting in a net payment of $30.4 million in total CLMP credits. In 2021, INCs paid $33.4 million in CLMP charges in the day-ahead market, were paid $60.3 million in CLMP credits in the balancing energy market resulting in a net payment of $26.9 million in total CLMP credits. In 2021, up to congestion (UTCs) paid $62.8 million in CLMP charges in the day-ahead market, were paid $102.6 million in CLMP credits in the balancing market resulting in a total payment of $39.8 million in total CLMP credits.

Table 11-13 Total CLMP credits and charges by transaction type (Dollars (Millions)): 2021

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$24.6	$0.0	$0.0	$24.6	($55.0)	$0.0	$0.0	($55.0)	$0.0	($30.4)
Demand	$54.8	$0.0	$0.0	$54.8	$38.8	$0.0	$0.0	$38.8	$0.0	$93.6
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$2.8	$2.8	$0.0	$0.0	($0.7)	($0.7)	$0.0	$2.1
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)
Export	($45.0)	$0.0	($0.6)	($45.6)	($7.6)	$0.0	$2.8	($4.7)	$0.0	($50.4)
Generation	$0.0	($1,093.5)	$0.0	$1,093.5	$0.0	$31.7	$0.0	($31.7)	$0.0	$1,061.8
Import	$0.0	($0.4)	$0.0	$0.4	$0.0	$14.5	$0.0	($14.5)	$0.0	($14.1)
INC	$0.0	($33.4)	$0.0	$33.4	$0.0	$60.3	$0.0	($60.3)	$0.0	($26.9)
Internal Bilateral	$377.5	$380.2	$2.7	($0.0)	$2.8	$2.8	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$62.8	$62.8	$0.0	$0.0	($102.6)	($102.6)	$0.0	($39.8)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	($0.2)	($0.9)	$0.0	($0.9)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.7	$0.0	$0.0	$0.7	$0.0	$0.7
Total	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$0.0	$995.3

Table 11-14 Total CLMP credits and charges by transaction type (Dollars (Millions)): 2020

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$16.1	$0.0	$0.0	$16.1	($26.2)	$0.0	$0.0	($26.2)	$0.0	($10.1)
Demand	$34.5	$0.0	$0.0	$34.5	$22.2	$0.0	$0.0	$22.2	$0.0	$56.7
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$3.1	$3.1	$0.0	$0.0	($0.5)	($0.5)	$0.0	$2.6
Explicit Congestion and Loss Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
Export	($34.7)	$0.0	$0.7	($34.0)	($9.0)	$0.0	$0.8	($8.2)	$0.0	($42.2)
Generation	$0.0	($564.7)	$0.0	$564.7	$0.0	$10.4	$0.0	($10.4)	$0.0	$554.3
Import	$0.0	($0.2)	$0.0	$0.2	$0.0	($1.8)	($0.0)	$1.8	$0.0	$2.0
INC	$0.0	($17.0)	$0.0	$17.0	$0.0	$34.6	$0.0	($34.6)	$0.0	($17.6)
Internal Bilateral	$177.3	$180.2	$2.9	$0.0	($1.5)	($1.5)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$60.8	$60.8	$0.0	$0.0	($77.5)	($77.5)	$0.0	($16.7)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.4)	($0.1)	$0.0	($0.1)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.0	$0.0	($0.3)	$0.0	($0.3)
Total	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.5	($77.6)	($133.8)	$0.0	$528.7

Table 11-15 shows the change in total CLMP credits and charges incurred by transaction type in 2020 and 2021. Total negative CLMP credits incurred by generation increased by $507.6 million, and total CLMP charges incurred by demand increased by $36.9 million. The total CLMP credits to up to congestion transactions (UTCs) increased by $23.1 million in 2021. Total day-ahead CLMP charges to UTCs increased by $2.0 million in 2021. Balancing CLMP credits to UTCs increased by $25.1 million in 2021.

Table 11-15 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): 2020 to 2021

	Change in CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$8.5	$0.0	$0.0	$8.5	($28.8)	$0.0	$0.0	($28.8)	$0.0	($20.4)
Demand	$20.3	$0.0	$0.0	$20.3	$16.6	$0.0	$0.0	$16.6	$0.0	$36.9
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	$0.0	($0.1)	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	($0.3)	($0.3)	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.5)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)
Export	($10.3)	$0.0	($1.3)	($11.6)	$1.5	$0.0	$2.0	$3.5	$0.0	($8.2)
Generation	$0.0	($528.8)	$0.0	$528.8	$0.0	$21.2	$0.0	($21.2)	$0.0	$507.6
Import	$0.0	($0.2)	$0.0	$0.2	$0.0	$16.2	$0.0	($16.2)	$0.0	($16.1)
INC	$0.0	($16.3)	$0.0	$16.3	$0.0	$25.7	$0.0	($25.7)	$0.0	($9.4)
Internal Bilateral	$200.2	$200.0	($0.2)	($0.0)	$4.3	$4.3	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$2.0	$2.0	$0.0	$0.0	($25.1)	($25.1)	$0.0	($23.1)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$1.0	$0.2	($0.8)	$0.0	($0.8)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$1.0	$0.0	$0.0	$1.0	$0.0	$1.0
Total	$218.6	($345.3)	($0.3)	$563.7	($5.6)	$68.5	($23.1)	($97.1)	$0.0	$466.6

Table 11-16 compares CLMP credits and charges for each transaction type between the dispatch run and pricing run in September through December, 2021. Total CLMP charges incurred by generation decreased by $0.4 million, and total CLMP charges incurred by demand increased by $1.3 million from the dispatch run to the pricing run. The total CLMP credits to DECs increased by $0.6 million, the total CLMP credits to INCs decreased by $0.0 million and the total CLMP credits to UTCs increased by $0.8 million from the dispatch run to the pricing run.

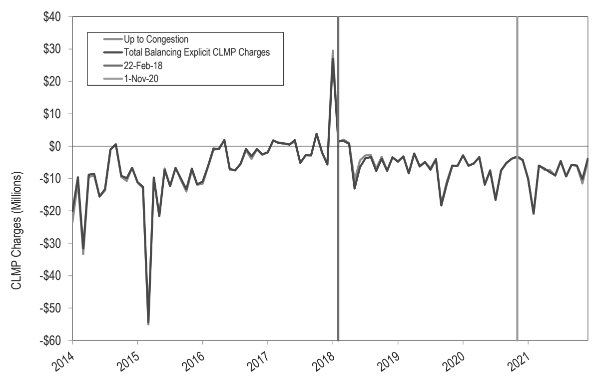
Table 11-16 Total CLMP credits and charges by dispatch run and pricing run (Dollars (Millions)): September through December, 2021

	CLMP Credits and Charges (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($8.4)	$1.2	($7.3)	($8.4)	$0.6	($7.8)	$0.0	($0.6)	($0.6)
Demand	($9.8)	$13.4	$3.6	($9.5)	$14.4	$4.9	$0.3	$1.0	$1.3
Demand Response	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)
Explicit Congestion Only	$1.2	($0.5)	$0.7	$1.2	($0.5)	$0.7	$0.0	($0.0)	$0.0
Explicit Congestion and Loss Only	($0.2)	$0.0	($0.2)	($0.2)	$0.0	($0.2)	($0.0)	$0.0	($0.0)
Export	($36.0)	($8.5)	($44.5)	($36.2)	($9.1)	($45.3)	($0.2)	($0.6)	($0.8)
Generation	$546.0	$2.6	$548.6	$547.1	$1.1	$548.2	$1.1	($1.5)	($0.4)
Import	($0.1)	($10.6)	($10.7)	($0.1)	($10.9)	($11.0)	($0.0)	($0.3)	($0.3)
INC	$19.8	($30.6)	($10.8)	$19.8	($30.6)	($10.8)	($0.0)	$0.0	($0.0)
Internal Bilateral	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)
Up to Congestion	$19.9	($27.1)	($7.2)	$19.9	($28.0)	($8.1)	$0.0	($0.9)	($0.8)
Wheel In	$0.0	($0.2)	($0.2)	$0.0	($0.2)	($0.2)	$0.0	($0.0)	($0.0)
Wheel Out	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0
Total	$532.4	($60.4)	$472.0	$533.7	($63.2)	$470.5	$1.3	($2.8)	($1.5)

UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from 2014 through 2021. Figure 11-2 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In 2021, 102.0 percent (-$102.6 million out of -$100.7 million) of negative balancing explicit CLMP charges was incurred by UTCs and -2.0 percent ($2.0 out of -$100.7 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-13). The vertical line at February 22, 2018, marks the date on which the FERC order that limited UTC trading to hubs, residual metered load, and interfaces was effective.[23] The vertical line at November 1, 2020, marks the date on which the FERC order that required PJM to allocate uplift to up to congestion transactions was effective.[24]

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTC: 2014 through 2021



Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences between the day-ahead and real-time market models including modeled constraints, the transfer capability (line limits) of the modeled constraints and the differences in deviations between day-ahead and real-time flows that result. The deviations are priced at the real-time LMPs.

For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than is modeled in the day-ahead market. In order to reduce processing time in the presence of large number of virtual bids and offers, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market.

23 For additional information about the FERC order, see the *2021 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
24 172 FERC ¶ 61,046 (2020).

Transmission constraints not modeled in the day-ahead market have unlimited transfer capability in the day-ahead market model. The inclusion of the actual, lower transmission capability in the real-time market requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion.[25] The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

As a day-ahead spread bid, UTCs can take advantage of and profit from LMP differences caused by modeling differences between the day-ahead and real-time market. UTCs clear between source and sink points with little or no price difference in the day-ahead market, and settle the resulting deviations at higher real-time price differences in the real-time market. The result is negative balancing congestion caused by and paid to UTCs in the form of CLMP credits. This is an example of false arbitrage because the UTCs cannot cause prices to converge and the profits to decrease. As a result of the FERC order requiring load to pay balancing congestion, load is responsible for paying the balancing congestion caused by UTCs.[26]

Table 11-18 provides an example of how UTCs can profit from differences in day-ahead and real-time models and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in day-ahead so the price at A and B is $1. The price spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and B. Total day-ahead congestion, which is the difference between CLMP charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore has deviations at Bus A (-200 MW) and at Bus B (+200 MW). The UTC must buy at bus A at the real-time price and sell at bus B at the real-time price to settle its deviations. The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The UTC must buy 200 MW at A at the real-time price of $1 and sell 200 MW at B at the real-time price of $6. The UTC pays $200 at A and is paid $1,200 at B. The result is a net payment to the UTC of $1,000 in balancing credits.

Table 11-17 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.[27]

25 Although it seems counter intuitive, as the amount of low cost generation decreases and the amount of high cost generation increases, the difference between load payments to generation and the payments received by generators goes down. High cost generation receives what load pays.

26 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180 (2016).

27 153 FERC ¶ 61,180 (2016).

The UTC did not and could not contribute to price convergence between the day-ahead and real-time market and did not and could not improve efficiency in system dispatch or commitment. The UTC took advantage of the modeling differences between the day-ahead and real-time markets. The UTC did significantly increase payments by load. Load was required to pay the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet real-time load. The differences in modeling would have resulted in only $250 in negative balancing congestion if there had been no UTCs.

Table 11-17 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day-Ahead MW	**Bus A**		**Bus B**	**Total MW**
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	**Bus A**		**Bus B**	**Total Day-Ahead Congestion**
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day-Ahead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	**Bus A**		**Bus B**	**Total Deviations**
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	**Bus A**		**Bus B**	**Balancing Congestion Credits**
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

Zonal and Load Aggregate Congestion

Zonal, and load aggregate, congestion is calculated on a constraint specific basis for a specific location or set of load pricing nodes (a zone or an aggregate). Local congestion is the difference between what load pays for energy and what generation is paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve a specific load, zone or load aggregate. Local congestion calculations account for the total difference between what the specified load pays and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. Congestion is the total congestion payments by load at the buses within a defined area minus total CLMP credits received by generation that supplied that load, given the transmission constraints. Congestion reflects the underlying characteristics of the entire power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of decremental bids and incremental offers and the geographic and temporal distribution of load.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of calculating the congestion from an individual constraint, the reference bus for each constraint calculation is the point that is just upstream of the constraint (the bus with the greatest negative price effect from the constraint), allowing any positive price effects of the constraint to be reflected as a positive CLMP.

In order to define the load that is actually paying congestion, congestion is appropriately assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the CLMP charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-18 shows day-ahead and balancing congestion by zone and the proportion of congestion resulting from constraints that are external to or internal to each zone, for 2021. Constraints are internal to a zone if both the source and sink points of the constraint are in the zone. AEP had the largest zonal congestion costs among all control zones in 2021. AEP had $163.1 million in zonal congestion costs, comprised of $198.2 million in zonal day-ahead congestion costs and -$35.1 million in zonal balancing congestion costs. The Three Mile Island Transformer, the Nottingham Series Reactor, the East Lima - Haviland Line, the Cumberland – Juniata Line and the Conastone Transformer contributed $48.5 million, or 29.7 percent of the AEP zonal congestion costs.[28]

Table 11-19 shows the congestion costs by zone for 2020.

Table 11-18 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): 2021

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$3.6	($6.3)	$0.7	$10.6	($0.2)	$1.0	($1.1)	($2.3)	$0.5	$7.8	$8.3
AEP	$53.2	($134.2)	$10.7	$198.2	($2.3)	$17.6	($15.2)	($35.1)	$33.4	$129.7	$163.1
APS	$25.6	($56.5)	$3.6	$85.8	($0.5)	$6.9	($5.9)	($13.3)	$3.7	$68.8	$72.4
ATSI	$23.1	($67.0)	$5.1	$95.1	($0.7)	$8.5	($7.6)	($16.8)	$0.8	$77.5	$78.3
BGE	$15.5	($28.3)	$2.2	$46.0	($0.0)	$4.3	($4.0)	($8.3)	$7.2	$30.5	$37.8
COMED	$32.5	($104.3)	$9.1	$145.9	($0.9)	$13.0	($11.2)	($25.1)	$24.1	$96.7	$120.8
DAY	$4.0	($17.3)	$1.3	$22.6	($0.2)	$2.3	($2.1)	($4.7)	$0.5	$17.5	$18.0
DOM	$86.2	($83.7)	$9.4	$179.3	($4.1)	$14.9	($15.7)	($34.8)	$38.7	$105.9	$144.6
DPL	$45.5	($7.1)	$3.1	$55.6	($1.8)	$1.7	($2.1)	($5.6)	$34.4	$15.6	$50.0
DUKE	$7.9	($25.4)	$2.1	$35.3	($0.3)	$3.6	($3.4)	($7.3)	$3.1	$24.9	$28.0
DUQ	$2.6	($11.2)	$0.6	$14.5	($0.1)	$1.7	($1.5)	($3.3)	$0.2	$11.0	$11.1
EKPC	$3.6	($13.6)	$1.0	$18.2	($0.2)	$1.9	($1.7)	($3.7)	$0.0	$14.4	$14.5
EXT	$9.1	($13.4)	$1.7	$24.3	($2.2)	$5.9	($4.6)	($12.7)	$1.0	$10.6	$11.6
JCPLC	$7.5	($17.2)	$1.3	$26.0	($0.3)	$2.5	($2.4)	($5.2)	$0.0	$20.7	$20.7
MEC	$12.3	($14.9)	$1.1	$28.3	($2.7)	$2.2	($2.3)	($7.2)	$9.3	$11.8	$21.1
OVEC	$0.2	($0.6)	$0.1	$0.9	($0.0)	$0.1	($0.1)	($0.3)	$0.1	$0.6	$0.7
PE	$11.1	($18.1)	$1.6	$30.8	($0.8)	$3.2	($2.2)	($6.3)	$3.2	$21.4	$24.5
PECO	$20.2	($30.0)	$2.3	$52.5	($0.7)	$4.3	($4.2)	($9.2)	$8.2	$35.2	$43.4
PEPCO	$14.1	($24.5)	$2.0	$40.6	($0.0)	$3.9	($3.5)	($7.5)	$1.0	$32.1	$33.1
PPL	$15.9	($39.8)	$3.4	$59.2	($0.8)	$4.8	($4.5)	($10.0)	$14.1	$35.0	$49.1
PSEG	$16.2	($32.5)	$3.0	$51.7	($1.3)	$5.3	($5.3)	($11.8)	($0.1)	$40.0	$39.9
REC	$2.1	($0.9)	$1.7	$4.8	($0.1)	$0.2	($0.2)	($0.5)	$3.0	$1.3	$4.3
Total	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$186.5	$808.7	$995.3

28 For additional information about the top 20 constraints that affected each zone, see the *2021 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-19 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): 2020

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$1.7	($3.9)	$0.7	$6.4	($0.1)	$0.5	($0.9)	($1.5)	$0.6	$4.3	$4.9
AEP	$23.7	($76.1)	$12.4	$112.3	($0.9)	$6.8	($11.9)	($19.5)	$25.0	$67.7	$92.7
APS	$17.6	($23.1)	$3.2	$43.9	($0.4)	$2.8	($4.6)	($7.8)	$4.8	$31.4	$36.2
ATSI	$10.7	($37.0)	$5.0	$52.8	($0.5)	$3.6	($6.3)	($10.4)	$0.5	$41.9	$42.4
BGE	$9.0	($13.9)	$1.9	$24.7	($0.2)	$1.7	($2.9)	($4.7)	$0.6	$19.4	$20.0
COMED	$0.9	($68.0)	$12.1	$81.0	($0.6)	$5.4	($8.3)	($14.4)	$14.2	$52.5	$66.7
DAY	$1.3	($10.1)	$1.4	$12.8	($0.1)	$0.9	($1.6)	($2.7)	$0.1	$10.0	$10.1
DOM	$40.3	($42.1)	$7.3	$89.6	($8.1)	$3.5	($10.4)	($21.9)	$18.1	$49.6	$67.7
DPL	$25.6	($2.7)	$2.8	$31.1	($0.5)	$1.0	($1.8)	($3.4)	$20.2	$7.5	$27.7
DUKE	$2.7	($14.1)	$2.0	$18.8	($0.2)	$1.4	($2.5)	($4.2)	$1.0	$13.7	$14.6
DUQ	$0.7	($6.9)	$0.7	$8.3	($0.1)	$0.8	($1.3)	($2.2)	$0.1	$6.0	$6.1
EKPC	$1.2	($7.3)	$1.1	$9.6	($0.1)	$0.7	($1.2)	($2.0)	$0.1	$7.5	$7.7
EXT	$3.8	($12.1)	$2.4	$18.3	($0.3)	$2.2	($3.5)	($6.0)	($0.1)	$12.5	$12.4
JCPLC	$3.8	($9.7)	$1.3	$14.8	($0.2)	$1.0	($2.2)	($3.4)	$0.0	$11.4	$11.4
MEC	$9.9	($5.5)	$1.1	$16.5	($0.8)	$1.0	($1.8)	($3.5)	$6.7	$6.3	$13.0
OVEC	$0.1	($0.5)	$0.6	$1.2	($0.0)	$0.1	($0.1)	($0.1)	$0.6	$0.5	$1.1
PE	$9.2	($5.9)	$1.3	$16.4	($0.3)	$0.9	($1.7)	($2.9)	$3.6	$9.9	$13.5
PECO	$4.7	($17.1)	$2.0	$23.9	($0.4)	$1.8	($3.6)	($5.8)	$2.1	$16.1	$18.1
PEPCO	$7.1	($11.7)	$1.6	$20.4	($0.2)	$1.5	($2.6)	($4.3)	$0.2	$15.9	$16.1
PPL	$10.6	($16.0)	$3.6	$30.1	($0.4)	$1.9	($3.8)	($6.1)	$7.4	$16.6	$24.0
PSEG	$8.2	($17.5)	$2.7	$28.4	($0.4)	$2.1	($4.1)	($6.6)	$0.6	$21.1	$21.7
REC	$0.3	($0.6)	$0.2	$1.1	($0.0)	$0.1	($0.2)	($0.3)	$0.0	$0.8	$0.8
Total	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.5	($77.6)	($133.8)	$106.2	$422.5	$528.7

In cases where the constraint causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the constraint is handled as a special case. In 2021, the total congestion costs associated with these special cases were $0.5 million or 0.1 percent of the total congestion costs. Table 11-18 and Table 11-19 include congestion allocations from these special case constraints.

There are five categories of constraint specific allocation special cases: congestion associated with constraints with no downstream load bus (no load bus); congestion associated with constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interfaces (closed loop interfaces); congestion associated with CT price setting logic; and congestion associated with nontransmission facility constraints in the day-ahead energy market and/or any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors (unclassified).[29]

Table 11-20 and Table 11-21 show total congestion by type of special case, congestion, and total congestion by zone. Closed loop interfaces and CT pricing logic generally result in negative congestion on a constraint specific basis. PJM's use of both the closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in 2021 or 2020.

29 While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals.

Table 11-20 CLMP charges and credits and total congestion collected by zone and special case logic (Dollars (Millions)): 2021

CLMP Credits and Charges (Millions)																	
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$10.5	$10.6	$0.0	($0.0)	$0.0	$0.0	($0.0)	($2.2)	($2.3)	$8.3	($0.0)	(0.4%)
AEP	$0.0	($0.0)	$0.0	$0.4	$0.1	$197.7	$198.2	$0.0	($0.5)	$0.0	($0.0)	($0.3)	($34.2)	($35.1)	$163.1	($0.4)	(0.2%)
APS	$0.0	($0.0)	$0.0	$0.2	$0.0	$85.5	$85.8	$0.0	($0.2)	$0.0	($0.0)	($0.1)	($13.0)	($13.3)	$72.4	($0.1)	(0.2%)
ATSI	$0.0	($0.0)	$0.0	$0.0	$0.1	$95.1	$95.1	$0.0	($0.3)	$0.0	$0.0	($0.1)	($16.4)	($16.8)	$78.3	($0.4)	(0.5%)
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$46.0	$46.0	$0.0	($0.1)	$0.0	$0.0	($0.1)	($8.1)	($8.3)	$37.8	($0.2)	(0.5%)
COMED	$0.8	($0.0)	$0.0	$4.2	$0.1	$140.7	$145.9	$0.0	($0.4)	$0.0	$0.0	($0.2)	($24.5)	($25.1)	$120.8	$4.5	3.7%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$22.6	$22.6	$0.0	($0.1)	$0.0	$0.0	($0.0)	($4.5)	($4.7)	$18.0	($0.1)	(0.5%)
DOM	$0.0	($0.0)	$0.0	$0.0	$0.1	$179.2	$179.3	$0.0	($0.4)	$0.0	$0.0	($0.3)	($34.1)	($34.8)	$144.6	($0.6)	(0.4%)
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$55.6	$55.6	$0.0	($0.1)	$0.0	$0.0	($0.0)	($5.5)	($5.6)	$50.0	($0.1)	(0.2%)
DUKE	$0.0	($0.0)	$0.0	$0.4	$0.0	$34.9	$35.3	($0.0)	($0.1)	$0.0	$0.0	($0.1)	($7.1)	($7.3)	$28.0	$0.3	1.0%
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$14.5	$14.5	$0.0	($0.1)	$0.0	$0.0	($0.0)	($3.3)	($3.3)	$11.1	($0.1)	(0.6%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$18.2	$18.2	$0.0	($0.1)	$0.0	$0.0	($0.0)	($3.6)	($3.7)	$14.5	($0.1)	(0.6%)
EXT	$0.9	($0.0)	$0.0	$0.2	$0.0	$23.2	$24.3	($0.0)	($2.7)	$0.0	$0.0	($0.0)	($9.9)	($12.7)	$11.6	($1.7)	(14.8%)
JCPLC	$0.0	($0.0)	$0.0	$0.0	$0.0	$25.9	$26.0	$0.0	($0.1)	$0.0	$0.0	($0.0)	($5.1)	($5.2)	$20.7	($0.1)	(0.6%)
MEC	$0.0	($0.0)	$0.0	$0.4	$0.0	$27.9	$28.3	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($7.1)	($7.2)	$21.1	$0.3	1.4%
OVEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.8	$0.9	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.3)	($0.3)	$0.7	$0.1	11.4%
PE	$0.0	($0.0)	$0.0	$0.0	$0.0	$30.8	$30.8	$0.0	($0.1)	$0.0	($0.6)	($0.0)	($5.5)	($6.3)	$24.5	($0.7)	(2.9%)
PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$52.5	$52.5	$0.0	($0.2)	$0.0	$0.0	($0.1)	($8.9)	($9.2)	$43.4	($0.2)	(0.5%)
PEPCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$40.6	$40.6	$0.0	($0.1)	$0.0	$0.0	($0.1)	($7.3)	($7.5)	$33.1	($0.1)	(0.4%)
PPL	$0.0	($0.0)	$0.0	$0.8	$0.0	$58.3	$59.2	($0.0)	($0.2)	$0.0	$0.0	($0.1)	($9.8)	($10.0)	$49.1	$0.5	1.1%
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$51.7	$51.7	$0.0	($0.2)	$0.0	$0.0	($0.1)	($11.6)	($11.8)	$39.9	($0.2)	(0.6%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$4.8	$4.8	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.5)	($0.5)	$4.3	($0.0)	(0.2%)
Total	$1.8	($0.3)	$0.0	$6.7	$0.7	$1,217.2	$1,226.2	($0.0)	($6.0)	$0.0	($0.6)	($1.9)	($222.5)	($230.9)	$995.3	$0.5	0.1%

Table 11-21 CLMP charges and credits and congestion collected by zone and special case logic (Dollars (Millions)): 2020

CLMP Credits and Charges (Millions)																	
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$6.4	$6.4	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($1.5)	($1.5)	$4.9	($0.0)	(0.4%)
AEP	$0.0	($0.1)	$0.0	$0.5	$0.4	$111.4	$112.3	($0.0)	($0.2)	$0.0	($0.1)	($0.2)	($19.1)	($19.5)	$92.7	$0.4	0.4%
APS	$0.0	($0.0)	$0.0	$0.2	$0.2	$43.6	$43.9	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($7.6)	($7.8)	$36.2	$0.2	0.5%
ATSI	$0.0	($0.0)	$0.0	$0.0	$0.2	$52.6	$52.8	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($10.1)	($10.4)	$42.4	($0.1)	(0.2%)
BGE	$0.0	($0.0)	$0.0	$0.0	$0.1	$24.6	$24.7	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($4.6)	($4.7)	$20.0	($0.1)	(0.3%)
COMED	$1.1	($0.0)	$0.0	$2.7	$0.3	$77.0	$81.0	($0.0)	($0.3)	$0.0	($0.0)	($0.1)	($14.0)	($14.4)	$66.7	$3.7	5.5%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.1	$12.7	$12.8	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.6)	($2.7)	$10.1	($0.0)	(0.2%)
DOM	$0.0	($0.0)	$0.0	$1.5	$0.3	$87.9	$89.6	($0.0)	($0.2)	$0.0	($0.3)	($0.1)	($21.3)	($21.9)	$67.7	$1.1	1.6%
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$31.0	$31.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($3.3)	($3.4)	$27.7	($0.0)	(0.1%)
DUKE	$0.0	($0.0)	$0.0	$0.0	$0.1	$18.7	$18.8	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($4.1)	($4.2)	$14.6	($0.0)	(0.2%)
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$8.3	$8.3	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.2)	($2.2)	$6.1	($0.0)	(0.3%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$9.6	$9.6	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($1.9)	($2.0)	$7.7	($0.0)	(0.2%)
EXT	$1.0	($0.0)	$0.0	$0.1	$0.1	$17.1	$18.3	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($5.8)	($6.0)	$12.4	$1.0	8.5%
JCPLC	$0.0	($0.0)	$0.0	$0.0	$0.1	$14.8	$14.8	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($3.3)	($3.4)	$11.4	($0.0)	(0.4%)
MEC	$0.0	($0.0)	$0.0	$0.5	$0.0	$16.1	$16.5	($0.0)	($0.0)	$0.0	($0.4)	($0.0)	($3.1)	($3.5)	$13.0	$0.0	0.3%
OVEC	$0.0	($0.0)	$0.0	$0.6	$0.0	$0.6	$1.2	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	$1.1	$0.6	55.5%
PE	$0.0	($0.0)	$0.0	$0.3	$0.1	$16.0	$16.4	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.8)	($2.9)	$13.5	$0.3	2.1%
PECO	$0.0	($0.0)	$0.0	$0.0	$0.1	$23.8	$23.9	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($5.7)	($5.8)	$18.1	($0.1)	(0.4%)
PEPCO	$0.0	($0.0)	$0.0	$0.0	$0.1	$20.3	$20.4	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($4.2)	($4.3)	$16.1	($0.0)	(0.3%)
PPL	$0.0	($0.0)	$0.0	$0.2	$0.1	$29.8	$30.1	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($6.0)	($6.1)	$24.0	$0.1	0.6%
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.1	$28.3	$28.4	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($6.5)	($6.6)	$21.7	($0.1)	(0.4%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.1	$1.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	($0.3)	$0.8	($0.0)	(0.3%)
Total	$2.1	($0.4)	$0.0	$6.7	$2.3	$651.8	$662.5	($0.0)	($1.7)	$0.0	($1.0)	($1.1)	($130.0)	($133.8)	$528.7	$6.9	1.3%

Fast Start Pricing Effect on Zonal Congestion

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. Table 11-22 compares the congestion costs between the dispatch run and the pricing run in September through December, 2021. The table shows that the implementation of fast starting pricing logic caused day-ahead total congestion costs to increase $1.3 million (or 0.2 percent), caused negative balancing congestion costs to increase $2.8 million (or 4.7 percent), and caused total congestion costs to decrease $1.5 million (or 0.3 percent) from the dispatch run to the pricing run in September through December, 2021. In comparing the two pricing results, the same MW, from the dispatch run in the day-ahead market and metered output in the real-time market, are used in the accounting cost calculations.

Table 11-22 Total congestion by dispatch and pricing run (Dollars (Millions)) September through December, 2021

	Congestion Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
AECO	$4.5	($0.6)	$3.9	$4.5	($0.6)	$3.9	$0.0	($0.0)	($0.0)
AEP	$85.7	($10.4)	$75.2	$85.9	($11.0)	$74.9	$0.2	($0.5)	($0.4)
APS	$39.2	($3.9)	$35.2	$39.2	($4.1)	$35.1	$0.1	($0.2)	($0.1)
ATSI	$42.2	($4.6)	$37.6	$42.3	($4.8)	$37.5	$0.1	($0.2)	($0.1)
BGE	$21.4	($2.3)	$19.0	$21.4	($2.4)	$19.0	$0.1	($0.1)	($0.1)
COMED	$65.1	($6.4)	$58.7	$65.1	($6.7)	$58.4	$0.0	($0.3)	($0.3)
DAY	$10.0	($1.2)	$8.7	$10.0	($1.3)	$8.7	$0.0	($0.1)	($0.0)
DEOK	$14.4	($1.9)	$12.5	$14.4	($1.9)	$12.5	$0.0	($0.1)	($0.0)
DOM	$81.7	($9.2)	$72.5	$81.9	($9.7)	$72.2	$0.2	($0.4)	($0.3)
DPL	$19.0	($1.1)	$18.0	$19.3	($1.1)	$18.2	$0.3	($0.0)	$0.2
DUQ	$7.0	($0.9)	$6.1	$7.0	($0.9)	$6.0	$0.0	($0.0)	($0.0)
EKPC	$8.5	($1.0)	$7.5	$8.5	($1.0)	$7.5	$0.0	($0.0)	($0.0)
EXT	$7.4	($1.5)	$5.9	$7.4	($1.5)	$5.8	($0.0)	($0.1)	($0.1)
JCPL	$11.9	($1.5)	$10.4	$11.9	($1.6)	$10.3	$0.0	($0.1)	($0.0)
METED	$12.4	($2.3)	$10.1	$12.5	($2.4)	$10.1	$0.0	($0.1)	($0.0)
OVEC	$0.3	($0.1)	$0.2	$0.3	($0.1)	$0.2	($0.0)	($0.0)	($0.0)
PECO	$20.2	($2.3)	$18.0	$20.3	($2.4)	$18.0	$0.1	($0.1)	($0.0)
PENELEC	$13.4	($1.7)	$11.6	$13.4	($1.8)	$11.6	$0.0	($0.0)	($0.0)
PEPCO	$18.9	($2.1)	$16.8	$19.0	($2.2)	$16.8	$0.1	($0.1)	($0.0)
PPL	$26.7	($2.8)	$23.9	$26.8	($2.9)	$23.9	$0.0	($0.1)	($0.1)
PSEG	$21.6	($2.6)	$19.0	$21.6	($2.7)	$18.9	$0.0	($0.1)	($0.1)
RECO	$1.1	($0.1)	$1.0	$1.1	($0.1)	$1.0	$0.0	($0.0)	($0.0)
Total	$532.4	($60.4)	$472.0	$533.7	($63.2)	$470.5	$1.3	($2.8)	($1.5)

Monthly Congestion

Table 11-23 shows day-ahead, balancing and inadvertent congestion costs by month for 2020 and 2021. Compared to 2020, total congestion costs increased in every month except for January and July. Total day-ahead congestion costs increased in every month except for July. Total negative balancing congestion costs decreased in May, July, September and December and increased in the other eight months.

In 2021, November had the highest day-ahead congestion costs. The top three constraints that contributed most to day-ahead costs were the Nottingham Series Reactor, the East Lima - Haviland Line and the Conastone - Northwest Line. The high shadow prices of the East Lima - Haviland constraint were a result of overload caused by a transmission outage in in the AEP Zone and the high shadow prices of the Conastone – Northwest were a result of overload caused by a transmission outage in the BGE Zone.

In 2021, February had the highest negative balancing congestion costs, as the combined result of cold weather, higher demand and higher prices. CT pricing logic also contributed to the higher negative balancing congestion costs in 2021 compared to 2020. The top three constraints that contributed most to the negative balancing congestion costs resulting from CT pricing logic were the Terminal Transformer, the Coffeen North – Roxford Flowgate and the Bergenfield – Leonia Line.

Table 11-23 Monthly congestion costs by market (Dollars (Millions)): 2020 and 2021

	Congestion Costs (Millions)							
	2020				2021			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$43.3	($5.6)	$0.0	$37.6	$53.2	($24.1)	($0.0)	$29.1
Feb	$28.7	($7.0)	($0.0)	$21.7	$90.3	($53.4)	$0.0	$36.9
Mar	$31.4	($5.6)	($0.0)	$25.8	$81.0	($25.8)	$0.0	$55.2
Apr	$24.2	($8.2)	$0.0	$16.0	$81.8	($18.0)	($0.0)	$63.9
May	$46.1	($19.5)	$0.0	$26.6	$104.4	($10.5)	$0.0	$94.0
Jun	$62.8	($10.7)	$0.0	$52.0	$91.0	($15.9)	$0.0	$75.1
Jul	$105.6	($23.8)	$0.0	$81.7	$78.7	($3.4)	$0.0	$75.4
Aug	$82.5	($14.0)	($0.0)	$68.5	$112.1	($16.6)	$0.0	$95.5
Sep	$78.1	($11.9)	$0.0	$66.1	$97.0	($7.2)	$0.0	$89.8
Oct	$52.5	($9.3)	$0.0	$43.2	$113.5	($14.4)	$0.0	$99.1
Nov	$41.3	($7.7)	$0.0	$33.6	$209.6	($34.3)	$0.0	$175.3
Dec	$66.2	($10.4)	$0.0	$55.8	$113.6	($7.3)	$0.0	$106.3
Total	$662.5	($133.8)	$0.0	$528.7	$1,226.2	($230.9)	$0.0	$995.3

Figure 11-3 shows PJM monthly total congestion cost for the 2008 through 2021.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): 2008 through 2021

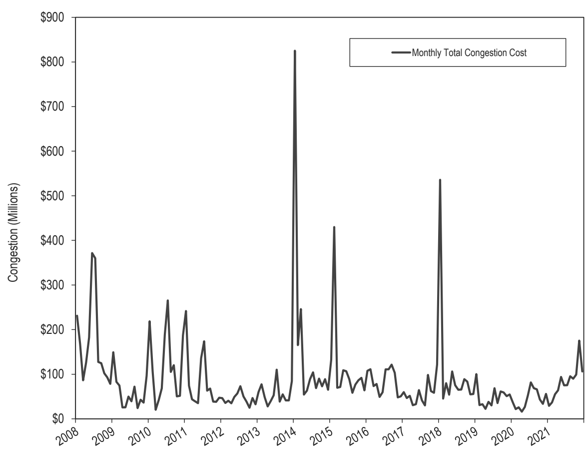


Table 11-24 shows monthly total CLMP credits and charges for each virtual transaction type in 2020 and 2021. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-24 show that virtuals were paid, in net, CLMP credits in 2021 and 2020. In 2021, 41.0 percent of the total credits to virtuals went to UTCs, compared to 37.7 percent in 2020.

Table 11-24 Monthly CLMP charges by virtual transaction type (Dollars (Millions)): 2020 and 2021

CLMP Credits and Charges (Millions)											
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2020	Jan	$0.2	($0.6)	($0.4)	$1.4	($1.8)	($0.4)	$3.7	($2.9)	$0.8	($0.0)
	Feb	$0.2	($0.2)	($0.1)	$1.3	($1.5)	($0.1)	$4.8	($6.1)	($1.3)	($1.5)
	Mar	($0.8)	($0.1)	($0.9)	$1.3	($1.6)	($0.2)	$4.8	($5.3)	($0.5)	($1.6)
	Apr	($0.6)	$0.8	$0.2	$1.9	($5.0)	($3.0)	$2.7	($3.4)	($0.7)	($3.5)
	May	$0.6	($0.6)	$0.0	$2.7	($5.1)	($2.4)	$7.3	($11.7)	($4.4)	($6.8)
	Jun	$1.0	($1.6)	($0.6)	$1.7	($2.8)	($1.2)	$7.7	($7.4)	$0.3	($1.5)
	Jul	$5.1	($3.7)	$1.4	$0.9	($3.5)	($2.6)	$9.1	($16.2)	($7.1)	($8.3)
	Aug	$5.1	($7.4)	($2.4)	$0.6	($1.9)	($1.3)	$5.8	($7.6)	($1.8)	($5.5)
	Sep	$2.5	($5.9)	($3.4)	$1.7	($1.5)	$0.1	$6.9	($5.3)	$1.6	($1.7)
	Oct	$1.0	($2.0)	($1.0)	$1.6	($3.2)	($1.6)	$2.8	($3.8)	($1.1)	($3.7)
	Nov	($1.1)	$1.4	$0.3	$3.0	($5.4)	($2.5)	$2.7	($3.4)	($0.7)	($2.9)
	Dec	$3.0	($6.2)	($3.2)	($1.0)	($1.3)	($2.4)	$2.5	($4.3)	($1.8)	($7.4)
	Total	$16.1	($26.2)	($10.1)	$17.0	($34.6)	($17.6)	$60.8	($77.5)	($16.7)	($44.4)
2021	Jan	$3.0	($8.0)	($5.0)	$0.5	($0.1)	$0.4	$4.0	($10.0)	($6.0)	($10.5)
	Feb	$11.8	($24.7)	($12.9)	$0.6	($4.0)	($3.5)	$7.9	($20.9)	($13.0)	($29.4)
	Mar	$6.7	($7.7)	($1.0)	$4.0	($8.1)	($4.2)	$4.9	($6.0)	($1.1)	($6.2)
	Apr	($1.1)	$1.9	$0.8	$4.9	($8.4)	($3.5)	$3.1	($7.2)	($4.2)	($6.8)
	May	$0.5	($3.1)	($2.7)	$2.4	($2.6)	($0.2)	$5.5	($7.4)	($1.9)	($4.8)
	Jun	$4.2	($6.5)	($2.3)	$0.9	($2.9)	($2.0)	$6.8	($9.2)	($2.3)	($6.6)
	Jul	$2.6	($2.3)	$0.2	$0.2	($0.7)	($0.5)	$6.0	($4.6)	$1.4	$1.1
	Aug	$5.2	($5.0)	$0.2	$0.0	($2.8)	($2.8)	$4.6	($9.3)	($4.7)	($7.3)
	Sep	$1.0	($0.7)	$0.2	$2.1	($3.8)	($1.7)	$5.2	($5.8)	($0.6)	($2.1)
	Oct	($4.3)	$2.3	($2.0)	$4.2	($6.9)	($2.7)	$4.9	($6.1)	($1.2)	($5.9)
	Nov	($2.4)	($1.5)	($3.9)	$12.4	($16.9)	($4.5)	$7.2	($11.5)	($4.3)	($12.7)
	Dec	($2.6)	$0.5	($2.1)	$1.1	($3.0)	($1.9)	$2.6	($4.5)	($1.9)	($5.9)
	Total	$24.6	($55.0)	($30.4)	$33.4	($60.3)	($26.9)	$62.8	($102.6)	($39.8)	($97.2)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. If two facilities are constrained during an hour the result is one constrained hour and two congestion event hours. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

In 2021, there were 56,425 day-ahead, congestion event hours compared to 78,239 day-ahead congestion event hours in 2020. Of the day-ahead congestion event hours in 2021, only 10,826 (19.2 percent) were also constrained in the real-time energy market (Table 11-27). In 2021, there were 23,068 real-time, congestion event hours compared to 21,984 real-time, congestion event hours in 2020. Of the real-time congestion event hours in 2021, 10,915 (47.3 percent) were also constrained in the day-ahead energy market (Table 11-28).

The top five constraints by congestion costs contributed $280.1 million, or 28.1 percent, of the total PJM congestion costs in 2021. The top five constraints were the Three Mile Island Transformer, the Nottingham Series Reactor, the Cumberland - Juniata Line, the Conastone Transformer, and the Brighton Circuit Breaker.

Two of the top 10 constraints by congestion costs are located in the BGE Zone in 2021 and in 2020, with one constraint common to both years (Figure 11-4).

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities except flowgates. Congestion event hours on lines decreased by 20,133 congestion event hours from 56,500 day-ahead, congestion event hours in 2020 to 36,367 day-ahead congestion event hours in 2021 (Table 11-27). Of the 20,133 congestion event hour decrease, 69.0 percent of the decreased hours were the result of reduction in congestion event hours from constraints in the AEP, BGE, DPL and PE Zones.

Real-time, congestion event hours increased on flowgates and transformers and decreased on interfaces and lines in 2021 (Table 11-28). Interfaces decreased by 1,246 congestion event hours from 1,343 real-time, congestion event hours in 2020 to 97 real-time congestion event hours in 2021. Of the 1,246 congestion event hour decrease, 94.8 percent of the decreased hours were on the PA Central Interface.[30]

Day-ahead congestion costs increased on all types of facilities except interfaces in 2021 compared to 2020 (Table 11-25). The decrease of day-ahead congestion costs on interfaces was primarily a result of the decrease in day-ahead congestion event hours on the PA Central Interface.

Negative balancing congestion costs increased on lines and transformers and decreased on interfaces and flowgates in 2021 compared to 2020 (Table 11-26). Table 11-25 provides congestion event hour subtotals and congestion cost subtotals comparing 2021 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[31] [32]

Table 11-25 Congestion summary (By facility type): 2021

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($49.6)	($202.7)	$6.3	$159.5	$4.2	$32.6	($16.0)	($44.4)	$115.0	8,604	6,340
Interface	$0.1	($1.6)	$0.1	$1.9	$0.2	$0.8	($0.9)	($1.5)	$0.5	38	97
Line	$232.1	($375.3)	$43.7	$651.2	($20.5)	$49.4	($62.1)	($132.0)	$519.1	36,367	11,147
Transformer	$114.3	($161.4)	$7.7	$283.4	($17.6)	$7.7	($10.4)	($35.7)	$247.8	7,367	2,335
Other	$114.3	($5.7)	$9.4	$129.5	$13.5	$18.8	($10.1)	($15.4)	$114.0	4,049	3,149
Unclassified	$0.5	($0.2)	($0.0)	$0.7	($0.0)	$0.7	($1.1)	($1.9)	($1.1)	NA	NA
Total	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$995.3	56,425	23,068

Table 11-26 Congestion summary (By facility type): 2020

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($30.6)	($87.6)	$16.9	$73.8	($0.8)	$6.2	($40.3)	($47.3)	$26.5	6,715	4,795
Interface	$3.2	($16.0)	$1.1	$20.3	$0.2	$2.6	($1.9)	($4.3)	$16.0	1,762	1,343
Line	$195.2	($224.3)	$38.9	$458.4	($14.0)	$22.6	($26.7)	($63.3)	$395.0	56,500	12,753
Transformer	$16.9	($60.3)	$9.1	$86.2	($2.2)	$6.8	($5.1)	($14.0)	$72.2	11,134	2,259
Other	$8.7	($11.4)	$1.3	$21.4	$2.1	$3.3	($2.5)	($3.7)	$17.7	2,128	834
Unclassified	($0.1)	($2.1)	$0.3	$2.3	$0.1	$0.1	($1.0)	($1.1)	$1.3	NA	NA
Total	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.5	($77.6)	($133.8)	$528.7	78,239	21,984

30 The PA Central Interface was created by PJM on October 1, 2018 to control for voltage contingencies associated with partially overlapping outages of three associated interface lines: Lackawanna - Hopatcong 500 kV line, Sunbury - Juniata 500 kV line and the Susquehanna - Wescosville 500 kV line. Scheduled outages caused PJM to enforce PA Central for potential voltage drop contingencies in the area.

31 Unclassified are congestion costs related to nontransmission facility constraints in the day-ahead energy market and any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

32 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-27 and Table 11-28 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the day-ahead energy market, the number of hours during which the facility is also constrained in the real-time energy market are presented in Table 11-27.[33]

Among the hours for which a facility was constrained in the real-time energy market, the number of hours during which the facility was also constrained in the day-ahead energy market are presented in Table 11-28.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in 2021. The number of congestion event hours in the day-ahead energy market was about twice the number of congestion event hours in the real-time energy market.

In the real-time market, PJM has the ability to model and monitor almost all PJM transmission facilities. In the day-ahead market, PJM can model and monitor only a portion of PJM transmission facilities. This difference in modeling is the basis of false arbitrage and the source of significant virtual profits. While more constraints are modeled and monitored in the PJM real-time market than the day-ahead market, there is significantly more network flow in the day-ahead market than in the real-time market as a result of virtual bids and offers. Virtual bids and offers also contribute to day-ahead market flows that do not align with realized real-time physical flows. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market, despite the fact that only a portion of PJM transmission facilities are modeled in the day-ahead market.

Table 11-27 Congestion event hours (day-ahead against real-time): 2020 and 2021

	Congestion Event Hours					
	2020			2021		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Interface	1,762	1,018	57.8%	38	7	18.4%
Transformer	11,134	1,312	11.8%	7,367	1,391	18.9%
Flowgate	6,715	1,441	21.5%	8,604	2,436	28.3%
Line	56,500	6,620	11.7%	36,367	5,239	14.4%
Other	2,128	267	12.5%	4,049	1,753	43.3%
Total	78,239	10,658	13.6%	56,425	10,826	19.2%

Table 11-28 Congestion event hours (real-time against day-ahead): 2020 and 2021

	Congestion Event Hours					
	2020			2021		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Interface	1,343	1,063	79.2%	97	7	7.2%
Transformer	2,259	1,337	59.2%	2,335	1,408	60.3%
Flowgate	4,795	1,446	30.2%	6,340	2,446	38.6%
Line	12,753	6,662	52.2%	11,147	5,288	47.4%
Other	834	268	32.1%	3,149	1,766	56.1%
Total	21,984	10,776	49.0%	23,068	10,915	47.3%

33 Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the day-ahead energy market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

Table 11-29 shows congestion costs by facility voltage class for 2021. Congestion costs in 2021 increased for all facility voltage classes except 161 kV and 765 kV facilities compared to 2020.

Table 11-29 Congestion summary (By facility voltage): 2021

	CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing					Event Hours		
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.3)	($1.2)	$0.2	$1.1	($0.5)	$0.3	($0.4)	($1.2)	($0.1)	18	5
500	$106.5	($111.3)	$6.6	$224.4	$5.1	$15.2	($10.9)	($21.0)	$203.4	3,791	2,871
345	($12.4)	($64.7)	$4.7	$57.0	($4.3)	$5.7	($6.9)	($16.8)	$40.1	3,505	1,551
230	$268.8	($214.9)	$29.3	$513.0	($12.7)	$30.1	($39.7)	($82.5)	$430.4	15,049	5,980
220	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	($0.0)	0	9
161	($2.7)	($8.5)	$0.4	$6.2	($0.4)	$0.5	($1.9)	($2.7)	$3.5	420	475
138	($25.4)	($320.5)	$18.4	$313.5	($0.1)	$48.4	($33.0)	($81.4)	$232.1	20,780	9,072
115	$49.0	($23.4)	$3.8	$76.2	($6.6)	$5.8	($5.3)	($17.8)	$58.4	5,816	2,429
69	$27.9	($2.3)	$3.9	$34.2	($0.8)	$3.3	($1.5)	($5.6)	$28.6	7,046	676
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
13.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Unclassified	$0.5	($0.2)	($0.0)	$0.7	($0.0)	$0.7	($1.1)	($1.9)	($1.1)	0	0
Total	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$995.3	56,425	23,068

Table 11-30 Congestion summary (By facility voltage): 2020

	CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing					Event Hours		
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.0)	($0.2)	$0.3	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	61	0
500	$32.1	($63.0)	$5.0	$100.0	$0.3	$10.6	($5.9)	($16.2)	$83.9	5,432	2,792
345	($10.4)	($44.4)	$12.0	$46.0	($0.1)	$2.0	($10.4)	($12.5)	$33.5	7,887	840
230	$141.5	($107.2)	$12.5	$261.2	$1.0	$12.2	($6.9)	($18.1)	$243.1	19,473	6,911
220	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
161	($14.0)	($40.9)	$5.8	$32.7	$0.6	$5.3	($15.8)	($20.6)	$12.1	2,770	2,049
138	($17.7)	($157.1)	$26.5	$165.8	($6.9)	$9.1	($35.3)	($51.2)	$114.6	23,780	6,138
115	$50.2	$12.0	$2.4	$40.6	($9.6)	$2.3	($1.8)	($13.7)	$26.9	8,408	2,968
69	$11.7	$1.2	$2.8	$13.3	($0.2)	($0.1)	($0.4)	($0.5)	$12.8	10,334	286
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
13.8	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	75	0
4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0
Unclassified	($0.1)	($2.1)	$0.3	$2.3	$0.1	$0.1	($1.0)	($1.1)	$1.3	NA	NA
Total	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.5	($77.6)	($133.8)	$528.7	78,239	21,984

Constraint Frequency

Table 11-31 lists the constraints for 2020 and 2021 that were most frequently binding and Table 11-32 shows the constraints which experienced the largest change in congestion event hours from 2020 to 2021. In Table 11-31, constraints are presented in descending order of total day-ahead event hours and real-time event hours for 2021. In Table 11-32, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from 2020 to 2021.

Table 11-31 Top 25 constraints: 2020 and 2021

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2020	2021	Change	2020	2021	Change	2020	2021	Change	2020	2021	Change
1	Nottingham	Other	870	2,062	1,192	306	1,280	974	9.9%	24%	14%	3%	15%	11%
2	Brighton	Other	0	1,086	1,086	0	1,478	1,478	0%	12%	12%	0%	17%	17%
3	Northwest Tap - Purdue	Flowgate	267	1,303	1,036	266	1,170	904	3%	15%	12%	3%	13%	10%
4	East Lima - Haviland	Line	732	1,591	859	244	825	581	8%	18%	10%	3%	9%	7%
5	Three Mile Island	Transformer	1,180	1,503	323	626	693	67	13%	17%	4%	7%	8%	1%
6	Prest - Tibb	Flowgate	0	1,125	1,125	0	995	995	0%	13%	13%	0%	11%	11%
7	Lenox - North Meshoppen	Line	1,349	913	(436)	1,308	1,156	(152)	15%	10%	(5%)	15%	13%	(2%)
8	Cedar Grove Sub - William	Line	142	1,174	1,032	40	582	542	2%	13%	12%	0%	7%	6%
9	Graceton - Safe Harbor	Line	1,145	1,267	122	712	427	(285)	13%	14%	1%	8%	5%	(3%)
10	Berwick - Koonsville	Line	1,196	1,684	488	3	1	(2)	14%	19%	6%	0%	0%	(0%)
11	Bagley - Raphael Road	Line	28	1,004	976	0	679	679	0%	11%	11%	0%	8%	8%
12	Gardners - Texas Eastern	Line	897	1,448	551	63	226	163	10%	17%	6%	1%	3%	2%
13	Sandburg	Flowgate	176	862	686	114	732	618	2%	10%	8%	1%	8%	7%
14	Ramapo (ConEd) - S Mahwah (RECO)	Line	335	1,248	913	0	0	0	4%	14%	10%	0%	0%	0%
15	Mt. Vernon - West Salem	Flowgate	214	662	448	185	540	355	2%	8%	5%	2%	6%	4%
16	Haumesser Road - Steward	Line	266	738	472	312	430	118	3%	8%	5%	4%	5%	1%
17	Face Rock	Other	665	802	137	44	233	189	8%	9%	2%	1%	3%	2%
18	Hope Creek - Silver Run	Line	4	751	747	0	221	221	0%	9%	9%	0%	3%	3%
19	Harwood - Susquehanna	Line	1,015	623	(392)	334	332	(2)	12%	7%	(4%)	4%	4%	(0%)
20	Monroe - Vineland	Line	1,665	846	(819)	90	77	(13)	19%	10%	(9%)	1%	1%	(0%)
21	Cumberland - Juniata	Line	523	645	122	241	256	15	6%	7%	1%	3%	3%	0%
22	Quad Cities	Transformer	1,177	840	(337)	0	0	0	13%	10%	(4%)	0%	0%	0%
23	Vienna	Transformer	0	644	644	0	171	171	0%	7%	7%	0%	2%	2%
24	Butler - Karns City	Line	325	707	382	6	22	16	4%	8%	4%	0%	0%	0%
25	East Side - North Delphos	Line	0	558	558	0	161	161	0%	6%	6%	0%	2%	2%

Table 11-32 Top 25 constraints year to year change in occurrence: 2020 and 2021

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2020	2021	Change	2020	2021	Change	2020	2021	Change	2020	2021	Change
1	Bagley - Graceton	Line	3,868	371	(3,497)	1,945	275	(1,670)	44%	4%	(40%)	22%	3%	(19%)
2	PA Central	Interface	1,412	0	(1,412)	1,237	56	(1,181)	16%	0%	(16%)	14%	1%	(13%)
3	Brighton	Other	0	1,086	1,086	0	1,478	1,478	0%	12%	12%	0%	17%	17%
4	DoeX530	Transformer	2,330	73	(2,257)	0	0	0	27%	1%	(26%)	0%	0%	0%
5	Nottingham	Other	870	2,062	1,192	306	1,280	974	10%	24%	14%	3%	15%	11%
6	Easton - Emuni	Line	2,859	708	(2,151)	9	5	(4)	33%	8%	(24%)	0%	0%	(0%)
7	Prest - Tibb	Flowgate	0	1,125	1,125	0	995	995	0%	13%	13%	0%	11%	11%
8	Northwest Tap - Purdue	Flowgate	267	1,303	1,036	266	1,170	904	3%	15%	12%	3%	13%	10%
9	Sub 85 - Sub 18	Flowgate	1,167	148	(1,019)	850	158	(692)	13%	2%	(12%)	10%	2%	(8%)
10	Sayreville - Sayreville	Line	1,706	31	(1,675)	0	0	0	19%	0%	(19%)	0%	0%	0%
11	Bagley - Raphael Road	Line	28	1,004	976	0	679	679	0%	11%	11%	0%	8%	8%
12	Cedar Grove Sub - William	Line	142	1,174	1,032	40	582	542	2%	13%	12%	0%	7%	6%
13	White Stone - Harmony Village	Line	1,233	0	(1,233)	286	0	(286)	14%	0%	(14%)	3%	0%	(3%)
14	Mountain	Transformer	1,874	390	(1,484)	0	0	0	21%	4%	(17%)	0%	0%	0%
15	East Lima - Haviland	Line	732	1,591	859	244	825	581	8%	18%	10%	3%	9%	7%
16	Logtown - North Delphos	Line	955	0	(955)	462	0	(462)	11%	0%	(11%)	5%	0%	(5%)
17	Sandburg	Flowgate	176	862	686	114	732	618	2%	10%	8%	1%	8%	7%
18	Cedar Grove Sub - Roseland	Line	1,136	14	(1,122)	84	6	(78)	13%	0%	(13%)	1%	0%	(1%)
19	Conastone - Peach Bottom	Line	1,178	1	(1,177)	23	5	(18)	13%	0%	(13%)	0%	0%	(0%)
20	New Carisle - Pletcher	Line	1,098	49	(1,049)	110	2	(108)	13%	1%	(12%)	1%	0%	(1%)
21	Paradise - BR Tap	Flowgate	703	83	(620)	482	64	(418)	8%	1%	(7%)	5%	1%	(5%)
22	East Moline	Flowgate	518	0	(518)	480	0	(480)	6%	0%	(6%)	5%	0%	(5%)
23	Hope Creek - Silver Run	Line	4	751	747	0	221	221	0%	9%	9%	0%	3%	3%
24	Grant - Greentown	Line	967	41	(926)	0	0	0	11%	0%	(11%)	0%	0%	0%
25	Ramapo (ConEd) - S Mahwah (RECO)	Line	335	1,248	913	0	0	0	4%	14%	10%	0%	0%	0%

Top Constraints

Table 11-33 and Table 11-34 show the top constraints contributing to congestion costs by facility for 2021 and 2020. The Three Mile Island Transformer was the largest contributor to congestion costs in 2021, with $88.2 million in total congestion costs and 8.9 percent of the total PJM congestion costs in 2021. The Nottingham Series Reactor is the second largest contributor to congestion costs in 2021. The high shadow prices of the Nottingham constraint were a result of overload caused by a transmission outage in the PE Zone in October 2021.

Table 11-33 Top 25 constraints affecting congestion costs: 2021[34]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Three Mile Island	Transformer	500	$37.2	($49.7)	$2.4	$89.2	($0.3)	($1.2)	($2.0)	($1.0)	$88.2	8.9%
2	Nottingham	Other	PECO	$75.5	$0.7	$6.1	$80.9	$4.8	$5.4	($2.8)	($3.4)	$77.5	7.8%
3	Cumberland - Juniata	Line	PPL	$6.7	($38.4)	$1.5	$46.6	($0.2)	($0.6)	($2.0)	($1.6)	$45.0	4.5%
4	Conastone	Transformer	500	$19.8	($17.0)	$1.0	$37.8	$0.5	$1.2	($0.7)	($1.4)	$36.4	3.7%
5	Brighton	Other	500	$38.2	$1.7	$2.8	$39.3	$7.3	$8.7	($5.0)	($6.4)	$33.0	3.3%
6	Hope Creek - Silver Run	Line	PSEG	($0.7)	($33.2)	$0.3	$32.8	($1.1)	($0.9)	$0.1	($0.1)	$32.7	3.3%
7	Conastone - Northwest	Line	BGE	$19.9	($12.8)	$1.8	$34.6	$5.5	$6.0	($1.5)	($2.0)	$32.6	3.3%
8	East Lima - Haviland	Line	AEP	($58.4)	($94.7)	$2.8	$39.2	($1.1)	$4.1	($3.7)	($8.8)	$30.3	3.0%
9	Juniata	Transformer	500	$11.3	($24.5)	($0.3)	$35.5	($2.4)	$2.3	($0.5)	($5.2)	$30.3	3.0%
10	Pleasant View - Ashburn	Line	DOM	$29.8	$1.8	$0.7	$28.7	$0.8	$0.4	($1.1)	($0.7)	$28.0	2.8%
11	Graceton - Safe Harbor	Line	BGE	$25.4	$0.7	$2.2	$26.9	$1.4	$1.0	($0.9)	($0.4)	$26.5	2.7%
12	Brambleton - Evergreen Mills	Line	DOM	$9.2	($15.6)	$0.6	$25.4	$0.0	$0.0	$0.0	$0.0	$25.4	2.5%
13	Prest - Tibb	Flowgate	MISO	($10.3)	($33.7)	$1.9	$25.2	$2.4	$2.9	($1.9)	($2.4)	$22.8	2.3%
14	Bagley - Raphael Road	Line	BGE	$18.9	($2.7)	$1.7	$23.4	$1.7	$2.2	($2.1)	($2.5)	$20.9	2.1%
15	Pleasant View	Transformer	DOM	$4.4	($18.6)	$0.5	$23.4	$1.3	$2.2	($2.3)	($3.2)	$20.3	2.0%
16	Northwest Tap - Purdue	Flowgate	MISO	($8.5)	($39.4)	($1.1)	$29.8	$1.4	$12.1	$0.4	($10.3)	$19.5	2.0%
17	Vienna	Transformer	DPL	$18.6	($6.8)	$0.6	$26.0	($10.6)	($3.2)	$0.5	($6.9)	$19.1	1.9%
18	Harwood - Susquehanna	Line	PPL	$3.7	($16.3)	$0.8	$20.9	($0.2)	$0.9	($0.9)	($2.0)	$18.8	1.9%
19	Lafayette	Flowgate	MISO	($4.0)	($17.6)	$0.0	$13.6	$0.5	$1.8	$0.4	($0.9)	$12.7	1.3%
20	Rappahanock - White Stone	Line	DOM	$33.2	$18.7	$1.6	$16.0	($2.7)	($0.7)	($1.5)	($3.5)	$12.5	1.3%
21	Gardners - Texas Eastern	Line	MEC	($1.0)	($13.9)	$0.2	$13.2	($1.6)	$0.5	($0.2)	($2.3)	$10.9	1.1%
22	Bagley - Graceton	Line	BGE	$8.7	($1.6)	$0.5	$10.7	$0.3	$0.6	($0.0)	($0.4)	$10.4	1.0%
23	Ashburn - Cochran Mill	Line	DOM	$8.6	($0.7)	$0.5	$9.9	$0.2	$0.3	($0.4)	($0.4)	$9.4	0.9%
24	Sandburg	Flowgate	MISO	($10.0)	($25.3)	$1.8	$17.1	($0.6)	$4.9	($2.5)	($8.0)	$9.2	0.9%
25	Lenox - North Meshoppen	Line	PE	$0.5	($11.1)	$0.9	$12.5	$0.7	$3.6	($1.6)	($4.5)	$8.0	0.8%
	Top 25 Total			$276.9	($450.0)	$31.9	$758.8	$8.0	$54.3	($32.0)	($78.3)	$680.4	68.4%
	All Other Constraints			$134.9	($297.1)	$35.4	$467.4	($28.3)	$55.6	($68.7)	($152.6)	$314.8	31.6%
	Total			$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$995.3	100.0%

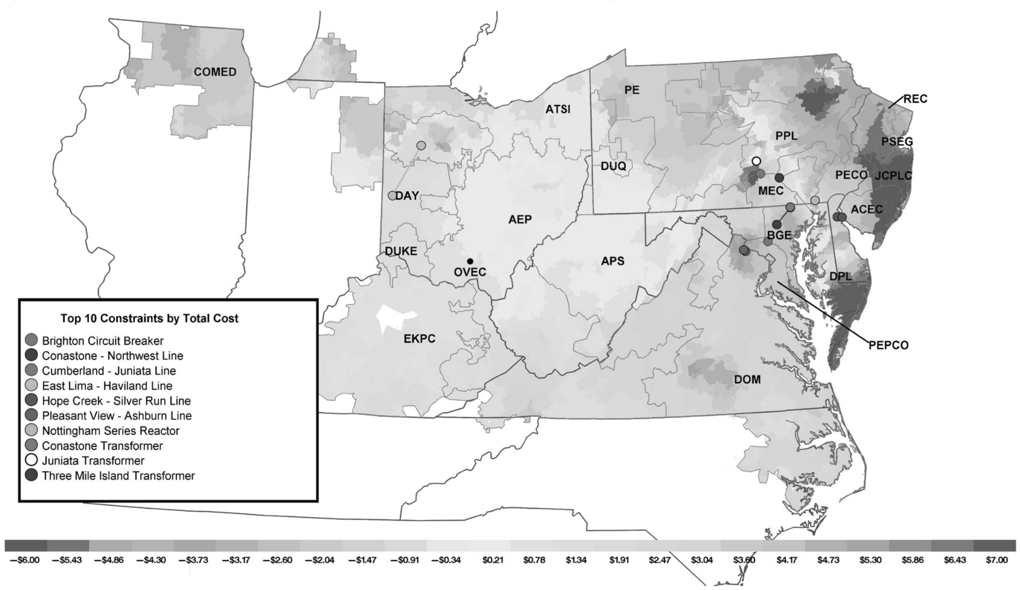
34 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-34 Top 25 constraints affecting congestion costs: 2020[35]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Bagley - Graceton	Line	BGE	$75.0	($4.5)	$3.1	$82.6	$1.5	$4.4	$2.0	($0.9)	$81.7	15.5%
2	Conastone - Graceton	Line	BGE	$8.4	($19.6)	$0.4	$28.4	$0.2	($0.7)	($0.1)	$0.8	$29.2	5.5%
3	Three Mile Island	Transformer	500	$13.4	($10.0)	$1.6	$25.0	$0.8	$1.1	($0.6)	($0.9)	$24.1	4.6%
4	Conastone - Peach Bottom	Line	500	$18.8	($1.1)	$0.5	$20.5	($0.0)	($0.1)	$0.0	$0.1	$20.6	3.9%
5	Harwood - Susquehanna	Line	PPL	$1.4	($17.8)	$0.6	$19.8	($0.2)	$0.4	($0.3)	($0.9)	$18.9	3.6%
6	Pleasant View - Ashburn	Line	DOM	$13.4	($4.6)	($0.2)	$17.9	$0.4	$0.8	($0.3)	($0.6)	$17.2	3.3%
7	Graceton - Safe Harbor	Line	BGE	$17.2	$2.2	$1.1	$16.0	$0.6	$0.9	($0.2)	($0.5)	$15.5	2.9%
8	Yukon	Transformer	500	($6.4)	($27.8)	$1.4	$22.7	($0.8)	$5.4	($2.7)	($8.8)	$13.9	2.6%
9	Cumberland - Juniata	Line	PPL	($0.3)	($13.5)	$0.9	$14.1	$0.1	($0.4)	($1.5)	($1.0)	$13.2	2.5%
10	PA Central	Interface	500	$1.1	($13.4)	$0.8	$15.3	$0.3	$1.9	($1.3)	($2.9)	$12.4	2.3%
11	Smithton - Yukon	Line	APS	($4.8)	($14.3)	$1.3	$10.7	$0.2	$0.4	($0.3)	($0.5)	$10.3	1.9%
12	Coolspring - Milford	Line	DPL	$1.5	($8.4)	$0.3	$10.2	($1.5)	($0.2)	($0.3)	($1.6)	$8.6	1.6%
13	Nottingham	Other	PECO	$9.7	$2.5	$1.3	$8.5	$0.4	($0.0)	($0.4)	($0.0)	$8.4	1.6%
14	East Lima - Haviland	Line	AEP	($14.5)	($21.7)	$0.7	$7.9	($0.2)	($0.5)	($0.0)	$0.2	$8.1	1.5%
15	Nelson - Vienna	Line	DPL	$4.7	($4.0)	$0.2	$8.9	($1.3)	($0.6)	($0.3)	($1.0)	$7.9	1.5%
16	Braidwood - East Frankfort	Line	COMED	($0.2)	($7.8)	$0.4	$8.0	($0.0)	$0.0	($0.3)	($0.3)	$7.7	1.5%
17	Mohomet - ChampTP	Flowgate	MISO	($1.4)	($6.6)	$2.1	$7.3	$0.1	($1.4)	($2.1)	($0.6)	$6.7	1.3%
18	Juniata	Transformer	500	$2.8	($3.9)	$0.1	$6.8	($0.2)	($0.1)	($0.1)	($0.1)	$6.7	1.3%
19	Pruntytown	Other	APS	($1.5)	($7.8)	($0.5)	$5.8	$0.0	($0.0)	$0.3	$0.3	$6.1	1.2%
20	Plymouth Meeting - Whitpain	Line	PECO	($0.4)	($5.2)	$0.1	$4.9	$0.3	$0.0	$0.1	$0.5	$5.3	1.0%
21	Logtown - North Delphos	Line	AEP	($15.3)	($25.2)	$2.1	$11.9	$0.0	$3.5	($3.3)	($6.8)	$5.2	1.0%
22	Paradise - BR Tap	Flowgate	MISO	($3.9)	($9.8)	($0.5)	$5.3	$0.0	$0.0	($0.3)	($0.3)	$5.0	1.0%
23	Loretto - Vienna	Line	DPL	$5.5	$1.4	$0.4	$4.6	($0.1)	($0.2)	($0.1)	$0.0	$4.6	0.9%
24	Seward - Towanda	Line	PE	$17.3	$12.7	($0.0)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	0.9%
25	Gardners - Texas Eastern	Line	MEC	$3.6	($0.8)	$0.4	$4.7	($0.3)	($0.1)	($0.0)	($0.2)	$4.5	0.8%
	Top 25 Total			$145.1	($208.7)	$18.6	$372.5	$0.5	$14.5	($12.1)	($26.1)	$346.3	65.5%
	All Other Constraints			$48.1	($193.0)	$48.9	$290.0	($15.2)	$27.0	($65.5)	($107.7)	$182.4	34.5%
	Total			$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.5	($77.6)	($133.8)	$528.7	100.0%

Figure 11-4 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in 2021. Two of the top 10 constraints are located in the BGE Zone: the Conastone Transformer and the Conastone – Northwest Line. Multiple constraints in the BGE Control Zone have been in the top 10 constraints by total congestion costs since 2016 as a result of RTEP projects in the BGE Zone.

Figure 11-4 Location of the top 10 constraints by total congestion costs: 2021



35 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless the location of the flowgates.

Figure 11-5 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time load-weighted average CLMP in 2021.

Figure 11-5 Location of top 10 constraints by balancing congestion costs: 2021

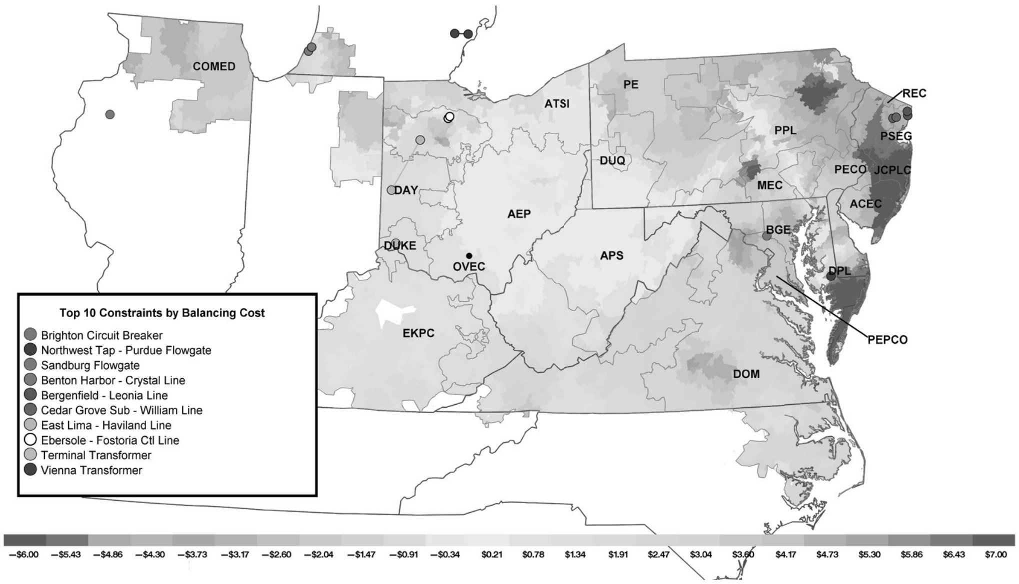
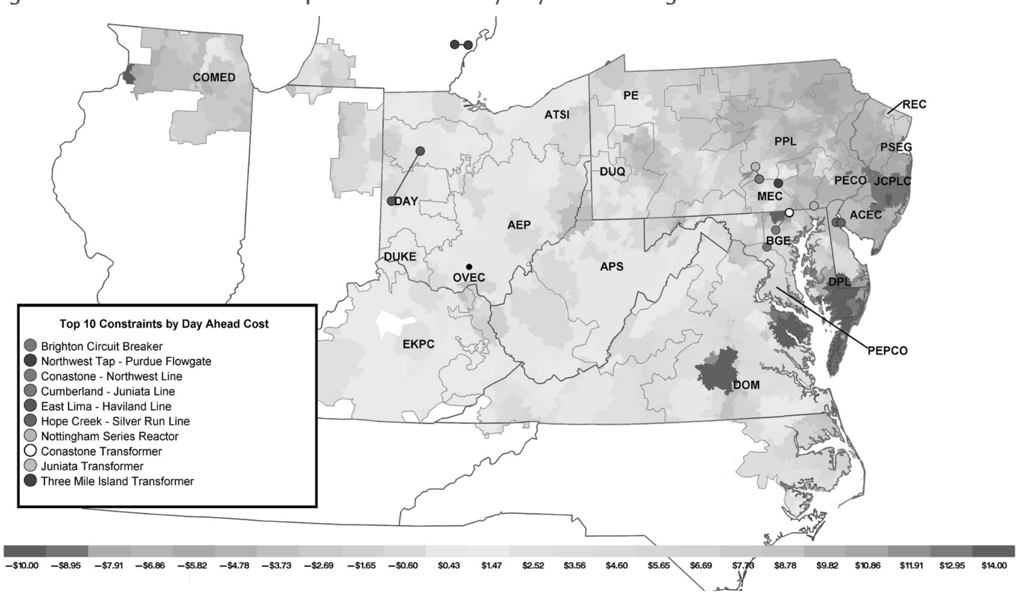


Figure 11-6 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead load-weighted average CLMP in 2021.

Figure 11-6 Location of the top 10 constraints by day-ahead congestion costs: 2021



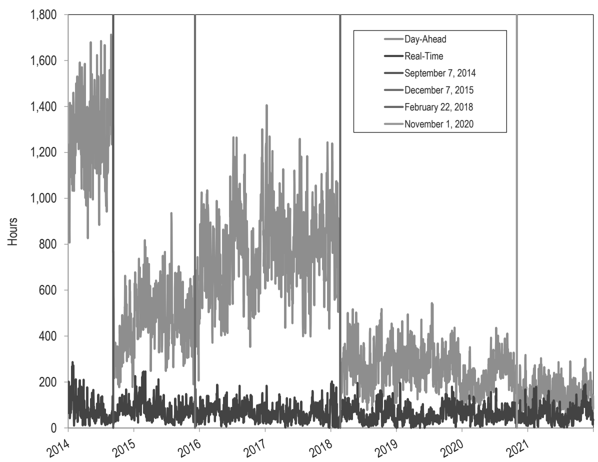
Congestion Event Summary: Impact of Changes in UTC Volumes

UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.[36]

In 2021, the average hourly cleared UTC MW decreased by 61.4 percent, compared to 2020. Day-ahead congestion event hours decreased by 27.9 percent from 78,239 congestion event hours in 2020 to 56,425 congestion event hours in 2021 (Table 11-27).

Figure 11-7 shows the daily day-ahead and real-time congestion event hours for 2014 through 2021.

Figure 11-7 Daily congestion event hours: 2014 through 2021



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the day-ahead and real-time energy markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Losses are the difference between what load (withdrawals) pay for energy and what generation (injections) are paid for energy, due to transmission line losses.

Losses increase with distance between sources and sinks and the amount of power moved. Total loss collected (loss surplus) increases with load, holding distance and resistance constant. Every incremental increase in load has to be met with a slightly larger increment of generation. The result is that the total energy losses increase as load increases.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the withdrawal loss charges minus injection loss credits, plus explicit loss charges, incurred in both the day-ahead energy market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[37] Unlike the other categories of marginal loss accounting, inadvertent loss charges are costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[38] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

The accounting definitions can be misleading. Load pays losses. Losses are the difference between what load pays for energy and what generation is paid for energy due to losses. Generation does not pay losses. Some generation receives a price lower than SMP and some generation receives a price greater than SMP due to the MLMP but that does not mean that generation is paying or being paid losses. It means that generation is being paid an LMP that is higher or lower than the

36 A series of FERC orders has affected UTC activity which has in turn affected congestion events in the day-ahead market. See Appendix F: Congestion and Marginal Losses.

37 PJM Operating Agreement Schedule 1 §3.7.

38 *Id.*

system load-weighted, average LMP due to losses on the system.

While PJM accounting focuses on MLMPs, the individual MLMP values at any bus are irrelevant to the calculation of total losses. Total losses are the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or losses, it merely changes the components of the LMP.

The MLMP component of LMP is the marginal cost of energy, due to losses associated with serving load at the bus. The MLMP at the load weighted reference bus is the marginal cost of energy at the load weighted reference bus (holding the proportion of load at every bus constant). Due to losses, MLMP is non zero at the load reference bus. The LMP at the load reference bus is the system marginal price of energy (SMP) plus the marginal cost of energy due to losses at the reference bus.

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

At the load-weighted reference bus, the LMP includes no congestion component, but does include a loss component. The load weighted, average MLMP across all load buses, calculated relative to that reference bus is positive. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses.

Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected by marginal losses. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs.

The residual difference between total marginal loss related load charges (day-ahead and balancing) and marginal loss related generation credits (day-ahead and balancing) after virtual bids have settled their marginal loss related credits and charges for their day-ahead and balancing positions is total loss. That is, losses are the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to losses, after virtual bids marginal loss related charges and credits are settled at the end of the market day. Load is the source of the net loss surplus after generation is paid and virtuals are settled at the end of the market day. Load pays losses. Generation does not pay losses.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the day-ahead and real-time energy markets priced at the marginal loss price component of LMP in the real-time energy market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

The total marginal loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments. The marginal loss surplus is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[39]

39 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 84 (Dec. 17, 2020).

Day-Ahead Implicit Load MLMP Charges

- **Day-Ahead Implicit Load MLMP Charges.** Day-ahead implicit load MLMP charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit load MLMP charges are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation MLMP Credits.** Day-ahead implicit generation MLMP credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit generation MLMP credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Implicit Load MLMP Charges.** Balancing implicit load MLMP charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit load MLMP charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Generation MLMP Credits.** Balancing implicit Generation MLMP credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit Generation MLMP credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load plus export ratio basis.[40]

Total Marginal Loss Cost

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses.

The total marginal loss cost in PJM for 2021 was $954.8 million, which was comprised of implicit load MLMP charges of -$2.7 million minus implicit generation MLMP credits of -$966.3 million plus explicit loss charges of -$8.9 million plus inadvertent loss charges of $0.0 million (Table 11-36).

Monthly marginal loss costs in 2021 ranged from $42.5 million in April to $112.8 million in August. Total marginal loss surplus increased in 2021 by $170.8 million or 107.1 percent from $159.6 million in 2020 to $330.4 million in 2021.

Table 11-35 shows the total marginal loss component costs and the total PJM billing for 2008 through 2021.

Table 11-35 Total loss component costs (Dollars (Millions)): 2008 through 2021[41 42]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,497	NA	$34,300	7.3%
2009	$1,268	(49.2%)	$26,550	4.8%
2010	$1,635	29.0%	$34,770	4.7%
2011	$1,380	(15.6%)	$35,890	3.8%
2012	$982	(28.8%)	$29,180	3.4%
2013	$1,035	5.5%	$33,860	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%
2016	$697	(28.1%)	$39,050	1.8%
2017	$691	(0.8%)	$40,170	1.7%
2018	$960	39.0%	$49,790	1.9%
2019	$642	(33.1%)	$41,680	1.5%
2020	$479	(25.5%)	$36,280	1.3%
2021	$955	99.5%	$54,130	1.8%

40 PJM Operating Agreement Schedule 1 §3.7.
41 The loss costs include net inadvertent charges.
42 In Table 11-35, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 11-36 shows PJM total marginal loss costs by accounting category for 2008 through 2021. Table 11-37 shows PJM total marginal loss costs by accounting category by market for 2008 through 2021.

Table 11-36 Total marginal loss costs by accounting category (Dollars (Millions)): 2008 through 2021

	Marginal Loss Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($237.2)	($2,641.5)	$92.4	$0.0	$2,496.7
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7
2016	($55.0)	($782.1)	($30.6)	($0.0)	$696.5
2017	($40.9)	($766.9)	($35.1)	$0.0	$690.8
2018	($42.2)	($1,014.3)	($11.9)	$0.0	$960.1
2019	($44.7)	($703.4)	($16.6)	($0.0)	$642.0
2020	($25.9)	($518.2)	($13.7)	$0.0	$478.5
2021	($2.7)	($966.3)	($8.9)	$0.0	$954.8

Table 11-37 Total marginal loss costs by market (Dollars (Millions)): 2008 through 2021

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($158.1)	($2,582.2)	$134.3	$2,558.4	($79.1)	($59.4)	($42.0)	($61.7)	$0.0	$2,496.7
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7
2016	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	($0.0)	$696.5
2017	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8
2018	($48.3)	($1,003.8)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.0)	$0.0	$960.1
2019	($47.1)	($700.3)	$43.3	$696.5	$2.4	($3.1)	($60.0)	($54.5)	($0.0)	$642.0
2020	($27.6)	($517.4)	$36.5	$526.3	$1.7	($0.8)	($50.3)	($47.7)	$0.0	$478.5
2021	($4.2)	($958.4)	$33.7	$987.9	$1.5	($7.9)	($42.5)	($33.1)	$0.0	$954.8

Table 11-38 and Table 11-39 show PJM accounting based total loss costs for each transaction type in 2021 and 2020.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transaction. In 2021, DECs were paid $1.0 million in MLMP credits in the day-ahead market, paid $4.5 million in MLMP in the balancing energy market and paid $3.4 million in total MLMP charges. In 2021, INCs paid $13.8 million in MLMP charges in the day-ahead market, were paid $17.0 million in MLMP credits in the balancing energy market and were paid $3.2 million in total MLMP credits. In 2021, up to congestion paid $34.3 million in MLMP charges in the day-ahead market, were paid $43.0 million in MLMP credits in the balancing energy market and received $8.8 million in total MLMP credits.

Table 11-38 Total loss costs by transaction type (Dollars (Millions)): 2021

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($1.0)	$0.0	$0.0	($1.0)	$4.5	$0.0	$0.0	$4.5	$0.0	$3.4
Demand	$16.2	$0.0	$0.0	$16.2	$7.8	$0.0	$0.0	$7.8	$0.0	$24.0
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.9)	($0.9)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($1.0)
Export	($21.0)	$0.0	($0.1)	($21.1)	($9.1)	$0.0	$0.6	($8.5)	$0.0	($29.6)
Generation	$0.0	($945.3)	$0.0	$945.3	$0.0	($19.1)	$0.0	$19.1	$0.0	$964.3
Import	$0.0	($1.4)	$0.0	$1.4	$0.0	($4.3)	$0.0	$4.3	$0.0	$5.7
INC	$0.0	($13.8)	$0.0	$13.8	$0.0	$17.0	$0.0	($17.0)	$0.0	($3.2)
Internal Bilateral	$1.6	$2.1	$0.5	$0.0	($1.6)	($1.6)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$34.3	$34.3	$0.0	$0.0	($43.0)	($43.0)	$0.0	($8.8)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)
Total	($4.2)	($958.4)	$33.7	$987.9	$1.5	($7.9)	($42.5)	($33.1)	$0.0	$954.8

Table 11-39 Total loss costs by transaction type (Dollars (Millions)): 2020

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($1.8)	$0.0	$0.0	($1.8)	$3.9	$0.0	$0.0	$3.9	$0.0	$2.1
Demand	$0.7	$0.0	$0.0	$0.7	$4.2	$0.0	$0.0	$4.2	$0.0	$4.9
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.4)
Export	($11.6)	$0.0	$0.0	($11.6)	($5.3)	$0.0	$0.4	($4.9)	$0.0	($16.5)
Generation	$0.0	($494.5)	$0.0	$494.5	$0.0	($7.4)	$0.0	$7.4	$0.0	$501.8
Import	$0.0	($0.7)	$0.0	$0.7	$0.0	($1.3)	($0.0)	$1.3	$0.0	$2.0
INC	$0.0	($7.7)	$0.0	$7.7	$0.0	$9.0	$0.0	($9.0)	$0.0	($1.3)
Internal Bilateral	($14.9)	($14.5)	$0.4	$0.0	($1.2)	($1.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$36.5	$36.5	$0.0	$0.0	($50.6)	($50.6)	$0.0	($14.1)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)
Total	($27.6)	($517.4)	$36.5	$526.3	$1.7	($0.8)	($50.3)	($47.8)	$0.0	$478.5

Table 11-40 compares MLMP credits and charges for each transaction type between the dispatch run and pricing run in September through December, 2021. Total MLMP charges incurred by generation increased by $1.5 million, and total MLMP charges incurred by demand increased by $0.2 million from the dispatch run to the pricing run. The total MLMP charges incurred by DECs increased by $0.1 million, the total MLMP credits to INCs increased by $0.4 million and the total CLMP credits to UTCs increased by $0.9 million from the dispatch run to the pricing run.

Table 11-40 Total loss costs by dispatch and pricing run (Dollars (Millions)): September through December, 2021

	Marginal Loss Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($2.0)	$2.7	$0.7	($2.0)	$2.8	$0.8	($0.0)	$0.1	$0.1
Demand	($1.3)	$2.5	$1.2	($1.3)	$2.7	$1.4	$0.0	$0.2	$0.2
Demand Response	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)
Explicit Congestion and Loss Only	($0.3)	($0.0)	($0.3)	($0.3)	($0.0)	($0.3)	($0.0)	($0.0)	($0.0)
Export	($8.9)	($3.7)	($12.5)	($8.9)	($3.9)	($12.8)	($0.0)	($0.2)	($0.2)
Generation	$374.1	$8.8	$382.9	$375.2	$9.2	$384.5	$1.1	$0.4	$1.5
Import	$0.5	$2.2	$2.7	$0.5	$2.3	$2.8	$0.0	$0.1	$0.1
INC	$6.7	($8.1)	($1.5)	$6.7	($8.6)	($1.9)	$0.0	($0.5)	($0.4)
Internal Bilateral	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	($0.0)
Up to Congestion	$11.5	($15.1)	($3.6)	$11.5	($16.0)	($4.5)	$0.0	($0.9)	($0.9)
Wheel In	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)
Total	$380.3	($10.7)	$369.6	$381.4	($11.4)	$370.0	$1.1	($0.7)	$0.5

Monthly Marginal Loss Costs

Table 11-41 shows a monthly summary of marginal loss costs by market type for 2020 and 2021.

Table 11-41 Monthly marginal loss costs (Millions): 2020 and 2021

	Marginal Loss Costs (Millions)							
	2020				2021			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$49.8	($5.3)	($0.0)	$44.5	$62.0	($2.1)	($0.0)	$59.9
Feb	$39.8	($4.6)	($0.0)	$35.2	$107.7	($5.1)	$0.0	$102.7
Mar	$32.4	($3.5)	($0.0)	$28.8	$50.8	($3.7)	$0.0	$47.2
Apr	$25.9	($3.4)	($0.0)	$22.5	$44.4	($1.8)	($0.0)	$42.5
May	$30.4	($4.8)	$0.0	$25.7	$53.4	($3.0)	$0.0	$50.4
Jun	$41.0	($4.3)	$0.0	$36.7	$76.1	($2.8)	$0.0	$73.3
Jul	$73.2	($6.1)	$0.0	$67.0	$98.5	($2.5)	$0.0	$96.1
Aug	$59.8	($5.8)	($0.0)	$54.0	$113.6	($0.8)	$0.0	$112.8
Sep	$39.1	($4.4)	$0.0	$34.8	$88.9	($3.5)	$0.0	$85.4
Oct	$37.0	($3.0)	$0.0	$34.0	$98.6	($2.7)	($0.0)	$95.9
Nov	$37.8	($1.4)	$0.0	$36.4	$116.5	($4.0)	$0.0	$112.4
Dec	$59.9	($1.1)	$0.0	$58.8	$77.4	($1.2)	($0.0)	$76.3
Total	$526.3	($47.7)	$0.0	$478.5	$987.9	($33.1)	$0.0	$954.8

Figure 11-8 shows PJM monthly marginal loss costs for 2008 through 2021.

Figure 11-8 Monthly marginal loss cost (Dollars (Millions)): 2008 through 2021

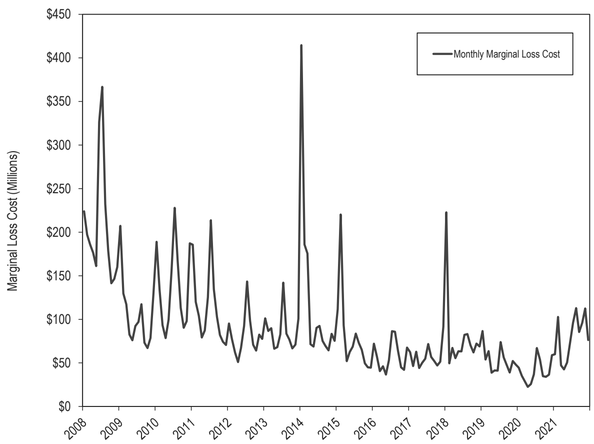


Table 11-42 shows the monthly total loss charges for each virtual transaction type for 2020 and 2021.

Table 11-42 Monthly loss charges by virtual transaction type (Dollars (Millions)): 2020 and 2021

Marginal Loss Charges (Millions)											
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2020	Jan	($0.1)	$0.1	($0.0)	$0.7	($0.9)	($0.2)	$3.7	($5.2)	($1.5)	($1.7)
	Feb	($0.1)	$0.2	$0.0	$0.6	($0.8)	($0.2)	$3.2	($4.4)	($1.2)	($1.3)
	Mar	($0.3)	$0.4	$0.1	$0.6	($0.7)	($0.1)	$2.5	($3.7)	($1.2)	($1.3)
	Apr	($0.2)	$0.4	$0.1	$0.6	($0.7)	($0.1)	$2.3	($3.5)	($1.2)	($1.1)
	May	($0.1)	$0.2	$0.1	$0.8	($0.8)	$0.0	$3.7	($4.8)	($1.1)	($0.9)
	Jun	($0.2)	$0.5	$0.2	$0.5	($0.6)	($0.1)	$3.1	($4.6)	($1.4)	($1.3)
	Jul	($0.3)	$0.8	$0.4	$0.9	($0.9)	($0.0)	$5.1	($6.5)	($1.4)	($1.0)
	Aug	($0.1)	$0.4	$0.3	$0.6	($0.7)	($0.1)	$4.1	($6.2)	($2.2)	($2.0)
	Sep	($0.1)	$0.2	$0.2	$0.5	($0.6)	($0.1)	$2.8	($4.2)	($1.4)	($1.4)
	Oct	$0.0	$0.1	$0.2	$0.7	($0.8)	($0.1)	$2.5	($3.0)	($0.6)	($0.5)
	Nov	($0.5)	$0.6	$0.1	$0.7	($0.8)	($0.0)	$1.6	($2.1)	($0.4)	($0.4)
	Dec	$0.3	$0.1	$0.4	$0.7	($0.9)	($0.3)	$1.9	($2.4)	($0.5)	($0.4)
	Total	($1.8)	$3.9	$2.1	$7.7	($9.0)	($1.3)	$36.5	($50.6)	($14.1)	($13.3)
2021	Jan	$0.3	($0.1)	$0.2	$0.8	($1.1)	($0.3)	$2.2	($2.6)	($0.4)	($0.5)
	Feb	$1.1	($0.7)	$0.4	$0.8	($0.9)	($0.1)	$4.5	($4.7)	($0.2)	$0.1
	Mar	$0.2	$0.2	$0.4	$1.2	($1.3)	($0.2)	$2.5	($3.2)	($0.7)	($0.5)
	Apr	($0.3)	$0.3	$0.1	$1.2	($1.1)	$0.0	$1.8	($2.2)	($0.4)	($0.2)
	May	($0.0)	$0.1	$0.0	$1.0	($1.1)	($0.1)	$2.5	($3.2)	($0.7)	($0.7)
	Jun	$0.1	$0.1	$0.2	$0.7	($1.0)	($0.2)	$3.2	($4.2)	($1.1)	($1.0)
	Jul	($0.1)	$0.5	$0.5	$0.8	($0.9)	($0.1)	$3.6	($3.8)	($0.2)	$0.1
	Aug	($0.4)	$1.2	$0.8	$0.6	($1.1)	($0.4)	$2.5	($3.1)	($0.6)	($0.3)
	Sep	($0.1)	$0.3	$0.2	$1.1	($1.7)	($0.5)	$2.5	($4.5)	($2.0)	($2.3)
	Oct	($1.1)	$0.9	($0.2)	$1.6	($1.9)	($0.3)	$2.5	($3.4)	($1.0)	($1.4)
	Nov	($0.6)	$0.8	$0.2	$2.9	($3.5)	($0.6)	$4.6	($5.4)	($0.8)	($1.1)
	Dec	($0.3)	$0.8	$0.5	$1.0	($1.5)	($0.5)	$1.9	($2.7)	($0.8)	($0.7)
	Total	($1.0)	$4.5	$3.4	$13.8	($17.0)	($3.2)	$34.3	($43.0)	($8.8)	($8.5)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs (which are negative), the total marginal loss costs (which are positive) and net residual market adjustments (which can be net positive or negative). The total system energy costs are equal to the net implicit energy charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit load MLMP charges less implicit generation MLMP credits) plus net explicit loss charges plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more injection credits than withdrawal charges in every hour. The greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). Total system energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-43 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for 2008 through 2021. The total marginal loss surplus increased $170.8 million or 107.1 percent in 2021 from 2020.

Table 11-43 Marginal loss surplus (Dollars (Millions)): 2008 through 2021[43]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustments			
	System Energy Cost	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Marginal Loss Surplus
2008	($1,193.2)	$2,496.7	$0.0	$0.0	$0.0	$1,303.5
2009	($628.8)	$1,267.7	($0.0)	($0.4)	($0.1)	$639.4
2010	($797.9)	$1,634.8	$0.0	($0.7)	($0.0)	$837.7
2011	($793.8)	$1,379.5	$0.1	$0.7	($0.0)	$585.2
2012	($593.0)	$981.7	$0.1	($1.0)	$0.1	$389.6
2013	($687.6)	$1,035.3	$0.0	$2.0	($0.0)	$345.7
2014	($977.7)	$1,466.1	$0.0	($0.0)	($0.0)	$488.4
2015	($627.4)	$968.7	($0.0)	$6.3	$0.1	$335.0
2016	($466.3)	$696.5	($0.0)	$5.1	($0.1)	$225.2
2017	($475.2)	$690.8	($0.0)	$3.2	($0.2)	$212.6
2018	($636.7)	$960.1	$0.0	$1.1	($0.1)	$322.4
2019	($435.2)	$642.0	($0.0)	$3.2	($0.1)	$203.7
2020	($317.4)	$478.5	($0.0)	$1.7	($0.1)	$159.6
2021	($623.2)	$954.8	($0.0)	$1.3	($0.1)	$330.4

System Energy Costs

Energy Accounting

The system energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The system energy cost is based on the day-ahead and real-time energy components of LMP. Total system energy costs, analogous to total congestion costs or total loss costs, are equal to the withdrawal energy charges minus injection energy credits, incurred in both the day-ahead energy market and the balancing energy market, plus net inadvertent energy charges. Total system energy costs can be more accurately thought of as net system energy costs.

Total System Energy Costs

The total system energy cost for 2021 was -$623.2 million, which was comprised of implicit withdrawal energy charges of $42,312.4 million, implicit injection energy credits of $42,938.3 million, explicit energy charges of $0.0 million and inadvertent energy charges of $2.7 million. The monthly system energy costs for 2021 ranged from -$77.3 million in November to -$28.4 million in April.

43 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Table 11-44 shows total system energy costs and total PJM billing, for 2008 through 2021.

Table 11-44 Total system energy costs (Dollars (Millions)): 2008 through 2021[44 45]

	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($1,193)	NA	$34,300	(3.5%)
2009	($629)	(47.3%)	$26,550	(2.4%)
2010	($798)	26.9%	$34,770	(2.3%)
2011	($794)	(0.5%)	$35,890	(2.2%)
2012	($593)	(25.3%)	$29,180	(2.0%)
2013	($688)	15.9%	$33,860	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)
2016	($466)	(25.7%)	$39,050	(1.2%)
2017	($475)	1.9%	$40,170	(1.2%)
2018	($637)	34.0%	$49,790	(1.3%)
2019	($435)	(31.6%)	$41,680	(1.0%)
2020	($317)	(27.1%)	$36,280	(0.9%)
2021	($623)	96.4%	$54,130	(1.2%)

System energy costs for 2008 through 2021 are shown in Table 11-45 and Table 11-46. Table 11-45 shows PJM system energy costs by accounting category and Table 11-46 shows PJM system energy costs by market category.

Table 11-45 Total system energy costs by accounting category (Dollars (Millions)): 2008 through 2021

	System Energy Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$105,665.6	$106,860.0	$0.0	$1.2	($1,193.2)
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)
2016	$34,053.6	$34,510.1	$0.0	($9.8)	($466.3)
2017	$35,152.1	$35,634.4	$0.0	$7.1	($475.2)
2018	$43,805.9	$44,447.2	$0.0	$4.6	($636.7)
2019	$30,647.4	$31,081.1	$0.0	($1.5)	($435.2)
2020	$23,400.9	$23,720.8	$0.0	$2.5	($317.4)
2021	$42,312.4	$42,938.3	$0.0	$2.7	($623.2)

Table 11-46 Total system energy costs by market (Dollars (Millions)): 2008 through 2021

	System Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$81,789.8	$83,120.0	$0.0	($1,330.1)	$23,875.8	$23,740.0	$0.0	$135.7	$1.2	($1,193.2)
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)
2016	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($9.8)	($466.3)
2017	$35,490.1	$36,138.6	$0.0	($648.5)	($338.0)	($504.2)	$0.0	$166.2	$7.1	($475.2)
2018	$43,948.7	$44,659.7	$0.0	($711.0)	($142.9)	($212.6)	$0.0	$69.7	$4.6	($636.7)
2019	$31,034.3	$31,562.9	$0.0	($528.6)	($386.9)	($481.8)	$0.0	$94.9	($1.5)	($435.2)
2020	$23,581.5	$23,983.0	$0.0	($401.4)	($180.6)	($262.2)	$0.0	$81.6	$2.5	($317.4)
2021	$42,431.6	$43,109.9	$0.0	($678.2)	($119.3)	($171.5)	$0.0	$52.3	$2.7	($623.2)

44 The system energy costs include net inadvertent charges.
45 In Table 11-44, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 11-47 and Table 11-48 show the total system energy costs for each transaction type in 2021 and 2020. In 2021, generation was paid $32,198.2 million and demand paid $30,161.9 million in net energy payment. In 2020, generation was paid $17,019.0 million and demand paid $15,872.1 million in net energy payment.

Table 11-47 Total system energy costs by transaction type (Dollars (Millions)): 2021

System Energy Costs (Millions)									
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$1,518.4	$0.0	$0.0	$1,518.4	($1,544.8)	$0.0	$0.0	($1,544.8)	($26.4)
Demand	$29,593.8	$0.0	$0.0	$29,593.8	$568.1	$0.0	$0.0	$568.1	$30,161.9
Demand Response	($0.9)	$0.0	$0.0	($0.9)	$0.9	$0.0	$0.0	$0.9	($0.0)
Export	$1,046.1	$0.0	$0.0	$1,046.1	$684.7	$0.0	$0.0	$684.7	$1,730.8
Generation	$0.0	$32,003.9	$0.0	($32,003.9)	$0.0	$194.3	$0.0	($194.3)	($32,198.2)
Import	$0.0	$54.4	$0.0	($54.4)	$0.0	$247.6	$0.0	($247.6)	($301.9)
INC	$0.0	$777.3	$0.0	($777.3)	$0.0	($785.2)	$0.0	$785.2	$7.9
Internal Bilateral	$10,274.3	$10,274.3	$0.0	$0.0	$157.9	$157.9	$0.0	$0.0	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$13.9	$0.0	($13.9)	($13.9)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$13.9	$0.0	$0.0	$13.9	$13.9
Total	$42,431.6	$43,109.9	$0.0	($678.2)	($119.3)	($171.5)	$0.0	$52.3	($625.9)

Table 11-48 Total system energy costs by transaction type by (Dollars (Millions)): 2020

System Energy Costs (Millions)									
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$851.8	$0.0	$0.0	$851.8	($871.8)	$0.0	$0.0	($871.8)	($20.0)
Demand	$15,632.8	$0.0	$0.0	$15,632.8	$239.3	$0.0	$0.0	$239.3	$15,872.1
Demand Response	($0.3)	$0.0	$0.0	($0.3)	$0.3	$0.0	$0.0	$0.3	$0.0
Export	$598.0	$0.0	$0.0	$598.0	$359.2	$0.0	$0.0	$359.2	$957.2
Generation	$0.0	$17,008.7	$0.0	($17,008.7)	$0.0	$10.3	$0.0	($10.3)	($17,019.0)
Import	$0.0	$29.6	$0.0	($29.6)	$0.0	$84.9	$0.0	($84.9)	($114.5)
INC	$0.0	$445.5	$0.0	($445.5)	$0.0	($449.8)	$0.0	$449.8	$4.3
Internal Bilateral	$6,499.2	$6,499.2	$0.0	($0.0)	$65.6	$65.6	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$26.9	$0.0	($26.9)	($26.9)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$26.9	$0.0	$0.0	$26.9	$26.9
Total	$23,581.5	$23,983.0	$0.0	($401.4)	($180.6)	($262.2)	$0.0	$81.6	($319.9)

Table 11-49 compares the total system energy costs for each transaction type between the dispatch run and the pricing run in September through December, 2021. The system energy charges to demand increased $51.6 million, and the energy credits to generation increased $39.6 million from the dispatch run to the pricing run. The energy credits to DEC increased $35.3 million, the energy charges to INC increased $17.2 million from the dispatch run to the pricing run.

Table 11-49 Total system energy costs by dispatch and pricing run (Dollars (Millions)): September through December, 2021

System Energy Costs (Millions)									
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$648.2	($637.4)	$10.8	$650.2	($674.7)	($24.5)	$2.0	($37.3)	($35.3)
Demand	$11,998.0	$263.5	$12,261.5	$12,033.5	$279.6	$12,313.1	$35.5	$16.1	$51.6
Demand Response	($0.3)	$0.3	($0.0)	($0.3)	$0.3	$0.0	($0.0)	$0.0	$0.0
Export	$409.5	$247.8	$657.2	$410.6	$259.5	$670.1	$1.1	$11.7	$12.9
Generation	($12,964.8)	($54.6)	($13,019.4)	($13,003.2)	($55.8)	($13,059.1)	($38.4)	($1.2)	($39.6)
Import	($19.0)	($132.3)	($151.3)	($19.1)	($139.5)	($158.6)	($0.1)	($7.2)	($7.3)
INC	($335.0)	$327.4	($7.6)	($336.0)	$345.5	$9.6	($0.9)	$18.1	$17.2
Internal Bilateral	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	($0.0)
Wheel In	$0.0	($2.8)	($2.8)	$0.0	($3.0)	($3.0)	$0.0	($0.1)	($0.1)
Wheel Out	$0.0	$2.8	$2.8	$0.0	$3.0	$3.0	$0.0	$0.1	$0.1
Total	($263.5)	$14.7	($248.8)	($264.3)	$14.9	($249.4)	($0.8)	$0.2	($0.6)

Monthly System Energy Costs

Table 11-50 shows a monthly summary of system energy costs by market type for 2020 and 2021. Total balancing system energy costs in 2021 decreased from 2020. Monthly total system energy costs in 2021 ranged from -$77.3 million in November to -$28.4 million in April.

Table 11-50 Monthly system energy costs (Dollars (Millions)): 2020 and 2021

	System Energy Costs (Millions)							
	2020				2021			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($40.0)	$9.4	($0.1)	($30.7)	($42.7)	$5.0	($0.1)	($37.8)
Feb	($30.7)	$6.8	($0.3)	($24.2)	($73.5)	$9.8	$0.7	($63.0)
Mar	($25.5)	$5.2	($0.1)	($20.4)	($35.8)	$5.1	$0.0	($30.7)
Apr	($21.1)	$5.2	($0.0)	($15.9)	($30.4)	$2.1	($0.1)	($28.4)
May	($25.4)	$6.9	$0.4	($18.1)	($37.8)	$4.6	$0.1	($33.1)
Jun	($32.8)	$7.6	$0.6	($24.6)	($52.8)	$5.0	$0.3	($47.5)
Jul	($52.4)	$9.0	$0.9	($42.5)	($65.3)	$4.6	$0.8	($59.9)
Aug	($44.9)	$9.9	($0.2)	($35.2)	($75.6)	$1.1	$1.5	($73.0)
Sep	($30.7)	$7.6	$0.6	($22.5)	($61.5)	$3.9	$0.3	($57.3)
Oct	($29.4)	$7.3	$0.3	($21.9)	($68.8)	$5.8	($0.3)	($63.4)
Nov	($27.3)	$3.1	$0.1	($24.0)	($79.6)	$2.5	($0.2)	($77.3)
Dec	($41.2)	$3.5	$0.2	($37.4)	($54.4)	$2.8	($0.3)	($51.8)
Total	($401.4)	$81.6	$2.5	($317.4)	($678.2)	$52.3	$2.7	($623.2)

Figure 11-9 shows PJM monthly system energy costs for 2008 through 2021. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP (SMP) is the same for every bus in the market in every hour, the net energy bill is always negative (ignoring net interchange): (SMP x withdrawals + SMP x injections) < 0.) Assuming power balance is maintained in the presence of losses, the greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). With higher load levels, there are generally higher SMPs and more negative total energy charges.

Figure 11-9 Monthly system energy costs (Millions): 2008 through 2021

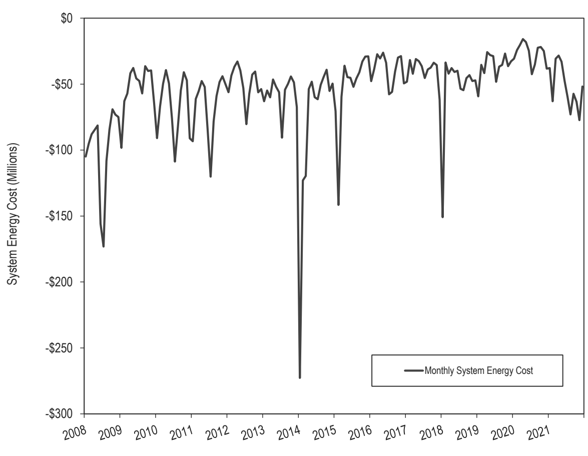


Table 11-51 shows the monthly total system energy costs for each virtual transaction type in 2021 and year of 2020. In 2021, DECs paid $1,518.4 million in energy charges in the day-ahead market, were paid $1,544.8 million in energy credits in the balancing energy market and were paid $26.4 million in total energy credits. In 2021, INCs were paid $777.3 million in energy credits in the day-ahead market, paid $785.2 million in energy charges in the balancing market and paid $7.9 million in total energy charges. In 2020, DECs paid $851.8 million in energy charges in the day-ahead market, were paid $871.8 million in energy credits in the balancing energy market and were paid $20.0 million in total energy credits. In 2020, INCs were paid $445.5 million in energy credits in the day-ahead market, paid $449.8 million in energy charges in the balancing energy market and paid $4.3 million in total energy charges. The system energy costs are zero for UTCs because the system energy costs for UTCs equal the difference in the energy component between source and sink and the energy component is the same at all buses.

Table 11-51 Monthly energy charges by virtual transaction type (Dollars (Millions)): 2020 and 2021

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2020	Jan	$44.4	($43.3)	$1.0	($44.0)	$43.2	($0.8)	$0.2
	Feb	$43.0	($42.4)	$0.6	($34.5)	$33.5	($1.0)	($0.3)
	Mar	$43.9	($44.0)	($0.1)	($32.1)	$31.7	($0.4)	($0.5)
	Apr	$42.4	($43.8)	($1.4)	($32.4)	$33.6	$1.2	($0.2)
	May	$59.9	($62.4)	($2.5)	($34.7)	$35.2	$0.5	($2.0)
	Jun	$79.9	($83.8)	($3.9)	($32.4)	$33.2	$0.8	($3.1)
	Jul	$116.8	($119.2)	($2.4)	($48.7)	$49.9	$1.2	($1.2)
	Aug	$99.9	($105.4)	($5.5)	($35.0)	$35.7	$0.7	($4.8)
	Sep	$77.6	($76.2)	$1.4	($33.4)	$32.6	($0.8)	$0.6
	Oct	$78.9	($81.4)	($2.5)	($39.2)	$40.9	$1.7	($0.8)
	Nov	$72.4	($74.8)	($2.4)	($38.4)	$38.8	$0.4	($2.1)
	Dec	$92.6	($95.1)	($2.5)	($40.5)	$41.4	$0.9	($1.6)
	Total	$851.8	($871.8)	($20.0)	($445.5)	$449.8	$4.3	($15.7)
2021	Jan	$76.5	($76.2)	$0.3	($41.9)	$41.6	($0.3)	($0.0)
	Feb	$167.0	($157.6)	$9.4	($54.4)	$51.4	($3.0)	$6.5
	Mar	$83.8	($89.0)	($5.2)	($50.9)	$53.3	$2.4	($2.8)
	Apr	$73.2	($70.5)	$2.7	($62.3)	$60.6	($1.7)	$1.0
	May	$81.7	($81.3)	$0.5	($52.7)	$52.5	($0.2)	$0.2
	Jun	$123.2	($127.6)	($4.4)	($46.1)	$46.5	$0.4	($4.0)
	Jul	$117.8	($113.7)	$4.1	($67.8)	$64.9	($2.9)	$1.3
	Aug	$145.0	($154.3)	($9.3)	($65.3)	$68.8	$3.5	($5.8)
	Sep	$142.0	($153.1)	($11.1)	($70.9)	$75.7	$4.8	($6.3)
	Oct	$179.4	($180.4)	($1.0)	($87.0)	$87.5	$0.5	($0.5)
	Nov	$175.3	($180.3)	($5.1)	($114.1)	$116.3	$2.3	($2.8)
	Dec	$153.5	($160.9)	($7.4)	($64.0)	$66.0	$2.0	($5.4)
	Total	$1,518.4	($1,544.8)	($26.4)	($777.3)	$785.2	$7.9	($18.5)

Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2021, PJM had a total installed capacity of 199,195.3 MW, of which 49,074.4 MW (24.6 percent) are coal fired steam units, 52,094.7 MW (26.2 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 199,195.3 MW of installed capacity, 72,821.7 MW (36.6 percent) are from units older than 40 years, of which 37,643.4 MW (51.7 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 17,342.6 MW (23.8 percent) are nuclear units.

Generation Retirements[2]

- There are 48,406.2 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 37,420.2 MW (77.3 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost natural gas.
- In 2021, 1,307.8 MW of generation retired. The largest generators that retired in 2021 were the 667.0 MW Chalk Point Unit 1 and 2 coal fired steam units located in the PEPCO Zone. Of the 1,307.8 MW of generation that retired, 669.4 MW (51.2 percent) were located in the PEPCO Zone.
- As of December 31, 2021, there are 7,081.0 MW of generation that have requested retirement after December 31, 2021, of which 1,300.0 MW (18.4 percent) are located in the DUKE Zone. Of the generation requesting retirement in the DUKE Zone, all 1,300.0 MW (100.0 percent) are coal fired steam units.

Generation Queue[3]

- There were 173,182.4 MW in generation queues, in the status of active, under construction or suspended, at the end of 2020. In 2021, the AG2 and AH1 queue windows closed, and the AH2 queue window opened. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On December 31, 2021, there were 254,914.6 MW in generation queues, in the status of active, under construction or suspended, an increase of 81,732.2 MW (47.2 percent) from the end of 2020.[4]
- As of December 31, 2021, 7,143 projects, representing 761,657.5 MW, have entered the queue process since its inception in 1998. Of those, 1,007 projects, representing 76,511.8 MW, went into service. Of the projects that entered the queue process, 3,269 projects, representing 430,231.1 MW (56.5 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- As of December 31, 2021, 254,914.6 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 41,074.4 MW (16.1 percent) of new generation in the queue are expected to go into service.
- The number of queue entries has increased during the past several years, primarily renewable projects. Of the 4,491 projects entered from January 2015 through December 2021, 3,344 projects (74.5 percent) were renewable. Of the 1,301 projects entered in 2021, 956 projects (73.5 percent) were renewable. Renewable projects make up 76.0 percent of all projects in the queue and those projects account for 75.1 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2021.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM. Planning. "Generator Deactivations," (Accessed on December 31, 2021) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM. Planning. "New Services Queue," (Accessed on December 31, 2021) <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
4 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

But of the 191,352.4 MW of renewable projects in the queue, only 9,781.6 MW (5.1 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. PJM's cost/benefit analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through December 31, 2021, PJM has completed four market efficiency cycles under Order No. 1000.[5]

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.

  But the use of an inaccurate cost/benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[6] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 770.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890[7]) to 174 for years 2008 through 2021 (post Order 890).

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project. Under the current approach, end of life projects are excluded from competition.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[8] In 2021, the PJM Board approved $1.11 billion in upgrades. As of December 31, 2021, the PJM Board

5 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

6 See PJM. "Transmission Construction Status," (Accessed on December 31, 2021) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

7 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

8 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

has approved $38.9 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of December 31, 2021, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[9]
- There were 10,753 transmission outage requests submitted in the first seven months of the 2021/2022 planning period. Of the requested outages, 74.8 percent of the requested outages were planned for less than or equal to five days and 9.9 percent of requested outages were planned for greater than 30 days. Of the requested outages, 43.6 percent were late according to the rules in PJM's Manual 3.

Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[10] (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results,

9 See "PJM Manual 03: Transmission Operations," Rev. 60 (November 17, 2021).
10 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)

- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing cost/benefit analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[11]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[12]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as

11 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

12 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[13] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require or even permit direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The MMU recognizes that the Commission has recently issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot

13 See *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. PJM is in the process of developing and finalizing significant modifications to the queue process which are expected to be filed with FERC in 2022. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. But the behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The incentives for such behavior should also be addressed, including appropriate nonrefundable fees, appropriate credit requirements, appropriate limits on the use of the suspended option and appropriate milestone requirements.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current cost/benefit analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an inaccurate cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

If it is retained, there are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. The current cost/benefit analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The cost/benefit analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost benefit analysis.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the day-ahead energy market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[14] As of December 31, 2021, PJM had an installed capacity of 199,195.3 MW, of which 49,074.4 MW (24.6 percent) are coal fired steam units, 52,094.7 MW (26.2 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 199,195.3 MW of PJM installed capacity, 32,253.1 MW (16.2 percent) are in the AEP Zone, of which 13,463.0 MW (41.7 percent) are coal fired steam units, 7,475.0 MW (23.2 percent) are combined cycle units and 2,071.0 MW (6.4 percent) are nuclear units.

14 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 12-1 Existing capacity: December 31, 2021 (By zone and unit type (MW))[15]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
ACEC	0.0	901.9	544.7	26.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	5.9	64.1	0.0	0.0	458.9	0.0	0.0	0.0	7.5	0.0	2,014.5
AEP	4.0	7,475.0	4,108.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	364.7	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	32,253.1
APS	80.4	2,843.7	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	29.6	0.0	18.3	114.4	0.0	0.0	5,299.0	0.0	0.0	0.0	985.1	0.0	10,725.0
ATSI	0.0	4,647.5	958.0	629.0	6.4	0.0	0.0	0.0	2,134.0	0.0	18.5	46.1	0.0	0.0	0.0	2,128.0	325.0	0.0	136.0	0.0	0.0	11,028.5
BGE	0.0	0.0	267.6	228.8	0.0	0.0	0.0	0.4	1,716.0	0.0	0.0	4.2	1.1	0.0	0.0	1,578.0	143.5	397.0	57.0	0.0	0.0	4,393.6
COMED	150.0	2,271.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	30.3	9.0	0.0	0.0	3,840.1	1,326.0	0.0	0.0	4,831.0	0.0	29,830.5
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	932.6
DUKE	18.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	200.0	0.0	0.0	1,857.0	47.0	0.0	0.0	0.0	0.0	3,415.0
DUQ	0.0	101.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	14.4	0.0	0.0	0.0	0.0	0.0	565.0	0.0	0.0	0.0	0.0	0.0	2,478.7
DOM	0.0	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	39.0	106.4	3,096.9	0.0	0.0	3,499.2	35.0	800.0	368.4	587.0	0.0	28,942.2
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	88.0	14.1	320.4	0.0	0.0	410.0	710.0	153.0	70.0	0.0	0.0	4,994.4
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,597.0
JCPLC	40.0	2,229.5	531.1	225.6	0.0	0.4	140.0	0.0	0.0	0.0	0.0	14.1	396.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,577.0
MEC	0.0	2,595.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	33.4	0.0	0.0	0.0	115.0	0.0	0.0	60.0	0.0	0.0	3,222.9
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	0.0	0.0	0.0	762.0	0.0	103.0	0.0	0.0	11,976.7
PE	28.4	1,900.0	350.5	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	17.8	13.5	0.0	0.0	6,053.5	610.0	0.0	42.0	1,100.4	0.0	10,912.0
PEPCO	0.0	1,736.5	764.2	308.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	2.5	0.0	0.0	1,229.0	1,164.1	0.0	52.0	0.0	0.0	5,265.0
PPL	20.0	5,558.5	304.6	286.2	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	35.0	0.0	0.0	2,547.9	2,449.0	0.0	29.0	216.5	0.0	14,725.6
PSEG	7.7	4,343.3	1,039.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	220.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,299.5
XIC	0.0	0.0	858.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	4,222.7
Total	348.5	52,094.7	24,708.3	4,035.1	43.8	32.0	4,792.0	3,040.6	33,452.6	176.1	218.5	349.0	4,842.2	0.0	0.0	49,074.4	8,312.6	1,350.0	1,096.5	11,228.4	0.0	199,195.3

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 199,195.3 MW of installed capacity, 48,811.3 MW (24.5 percent) are in Pennsylvania, of which 9,281.4 MW (19.0 percent) are coal fired steam units, 18,087.2 MW (37.1 percent) are combined cycle units and 8,843.8 MW (18.1 percent) are nuclear units.

Table 12-2 Existing capacity: December 31, 2021 (By state and unit type (MW))

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	0.0	0.0	410.0	710.0	0.0	70.0	0.0	0.0	2,412.4
IL	150.0	2,271.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	30.3	9.0	0.0	0.0	3,840.1	1,326.0	0.0	0.0	4,831.0	0.0	29,830.5
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	130.1	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	8,694.9
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	3,719.1
MD	20.0	2,717.0	1,684.5	552.7	0.0	0.0	0.0	0.4	1,716.0	0.0	76.0	18.9	333.4	0.0	0.0	2,987.0	1,307.6	550.0	109.0	295.0	0.0	12,367.5
MI	0.0	1,200.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,295.4
NC	0.0	165.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	0.0	18.0	0.0	1,006.5	0.0	0.0	0.0	0.0	0.0	0.0	208.0	0.0	1,712.5
NJ	47.7	7,474.7	2,115.0	251.6	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	29.0	680.6	0.0	0.0	458.9	3.0	0.0	179.1	7.5	0.0	14,891.0
OH	22.0	8,609.7	4,201.2	701.2	6.4	0.0	0.0	200.0	2,134.0	0.0	47.0	50.9	351.1	0.0	0.0	9,553.0	47.0	0.0	136.0	1,147.7	0.0	27,207.2
PA	49.9	18,087.2	1,544.5	1,584.7	20.6	0.0	1,583.0	1,445.7	8,843.8	176.1	40.5	85.1	106.5	0.0	0.0	9,281.4	4,146.0	0.0	234.0	1,582.3	0.0	48,811.3
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VA	0.0	8,973.0	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	33.0	112.4	2,200.4	0.0	0.0	2,494.2	495.0	800.0	368.4	12.0	0.0	27,374.5
WV	58.9	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	20.0	0.0	0.0	12,484.0	0.0	0.0	0.0	791.7	0.0	14,636.8
XIC	0.0	0.0	858.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	4,222.7
Total	348.5	52,094.7	24,708.3	4,035.1	43.8	32.0	4,792.0	3,040.6	33,452.6	176.1	218.5	349.0	4,842.2	0.0	0.0	49,074.4	8,312.6	1,350.0	1,096.5	11,228.4	0.0	199,195.3

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of December 31, 2021. Of the 199,195.3 MW of installed capacity, 72,821.7 MW (36.6 percent) are from units older than 40 years, of which 37,643.4 MW (51.7 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 17,342.6 MW (23.8 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): December 31, 2021

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Less than 20	348.5	45,876.9	10,371.4	0.0	43.8	32.0	0.0	297.2	0.0	164.1	20.0	260.3	4,842.2	0.0	0.0	3,475.0	82.0	0.0	47.4	11,204.4	0.0	77,065.1
20 to 40	0.0	6,026.8	13,814.6	960.0	0.0	0.0	3,003.0	427.2	16,110.0	12.0	25.0	88.7	0.0	0.0	0.0	7,956.0	18.0	0.0	843.1	24.0	0.0	49,308.4
40 to 60	0.0	191.0	522.3	3,075.1	0.0	0.0	1,789.0	340.0	17,342.6	0.0	173.5	0.0	0.0	0.0	0.0	34,613.6	6,451.1	1,350.0	0.0	0.0	0.0	65,848.2
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,976.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,029.8	1,761.5	0.0	206.0	0.0	0.0	6,973.5
Total	348.5	52,094.7	24,708.3	4,035.1	43.8	32.0	4,792.0	3,040.6	33,452.6	176.1	218.5	349.0	4,842.2	0.0	0.0	49,074.4	8,312.6	1,350.0	1,096.5	11,228.4	0.0	199,195.3

15 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction.

Figure 12-1 Capacity (MW) by age (years): December 31, 2021

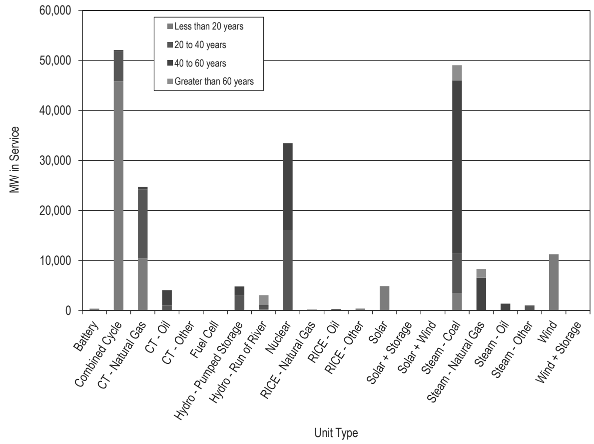


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and December 31, 2021. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through December 31, 2021

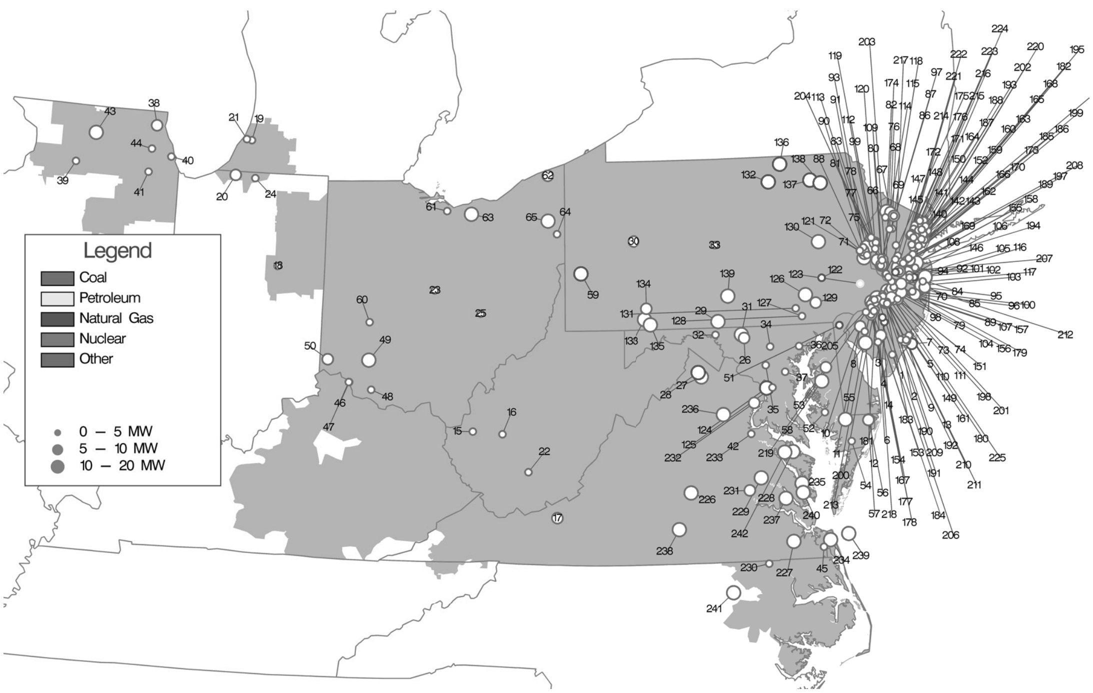


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through December 31, 2021

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	DPL WORCESTER NORTH 1 SP	111	JC PEMBERTON 2 SP	166	PS FORTY NINTH SOLAR 1 SP	221	PS W CALDWELL SOLAR 1 SP
2	ACE CATES ROAD 2 SP	57	DPL WORCESTER SOUTH 2 SP	112	JC QUAKERTOWN 9 SP	167	PS GLOUCESTER SOLAR 1 SP	222	PS W CALDWELL SOLAR 2 SP
3	ACE CEDAR BRANCH 1 SP	58	DPL WYE MILLS 1 SP	113	JC RICHLINE 3 SP	168	PS HACKENSACK 1 SP	223	PS WALDWICK SOLAR 1 SP
4	ACE EGG HARBOR-KELLOGG 1 FC	59	DUQ PIT MICROGRID 1 CT	114	JC RINGOES 1 SP	169	PS HIGHLAND PARK 3 BT	224	PS WEST ORANGE SOLAR 1 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	FE DOVETAIL 1 CT	115	JC SUSSEX 1 LF	170	PS HIGHLAND PARK 4 SP	225	PS WEST PEMBERTON 1 SP
6	ACE MAYS LANDING 1 SP	61	FE ERIE COUNTY 1 LF	116	JC TINTON FALLS 3 SP	171	PS HILLSDALE SOLAR 1 SP	226	VP BUCKINGHAM 1 SP
7	ACE MIDTOWN THERMAL 2 CT	62	FE GENEVA 1 LF	117	JC UPPER FREEHOLD 1 SP	172	PS HINCHMANS SOLAR 1 SP	227	VP GARDNER FARMS 1 SP
8	ACE OAK FAIRTON 1 SP	63	FE LORAIN 1 LF	118	JC WANTAGE 2 SP	173	PS HOBOKEN SOLAR 2 SP	228	VP GARDYS MILL ROAD 5 SP
9	ACE PEAR STREET 1 SP	64	FE MAHONING 1 LF	119	JC WARREN 1 SP	174	PS HOPEWELL 1 SP	229	VP HOLLYFIELD 1 SP
10	ACE PILESGROVE 1 SP	65	FE WARREN-EVERGREEN 1 CT	120	JC WASHBURN AVE 4 SP	175	PS HOPEWELL 2 BT	230	VP MURPHY 1 SP
11	ACE PILESGROVE 2 SP	66	JC AUGUSTA 1 SP	121	ME GLENDON 1 LF	176	PS JACKSON SOLAR 1 SP	231	VP NORTHEAST 2 LF
12	ACE PITTSGROVE 1 SP	67	JC BEAVER RUN 3 SP	122	ME READING HOSPITAL 1 CT	177	PS KINSLEY BEAVER 2 SP	232	VP OCCOQUAN 1 LF
13	ACE SEASHORE 1 SP	68	JC BERKSHIRE 2 SP	123	PE MORRIS ROAD 1 D	178	PS KINSLEY DEPTFORD 1 SP	233	VP OCCOQUAN 2 LF
14	ACE TANSBORO ROAD 1 FC	69	JC BERNARDS TOWNSHIP 1 SP	124	PEP CAPITAL POWER PLANT 1 CT	179	PS KUSER SOLAR 1 SP	234	VP OCEANA 1 SP
15	AEP BALLS GAP 1 BT	70	JC BRICKYARD 4 SP	125	PEP ROLLINS AVENUE 3 SP	180	PS LANDFILL 5 SP	235	VP PULLER 1 SP
16	AEP CHARLESTON 1 LF	71	JC COPPER HILL 4 SP	126	PL DART CONTAINER 1-2 LF	181	PS LAWNSIDE 14 BT	236	VP REMINGTON 1 SP
17	AEP CLOYDS MT 1 LF	72	JC CYPHERS ROAD 5 SP	127	PL HOLTWOOD 11	182	PS LEONIA SOLAR 1 SP	237	VP ROCHAMBEAU 1 SP
18	AEP DEERCREEK 1 SP	73	JC DIXSOLAR 51 SP	128	PL HOLTWOOD 13	183	PS LUMBERTON STACY HAINES 5 SP	238	VP TWITTYS CREEK 1 SP
19	AEP EAST WATERVLIET 1 SP	74	JC DIXSOLAR 52 SP	129	PL KEYSTONE 1 SP	184	PS MANTUA CREEK 7 BT	239	VP VIRGINIA OFFSHORE 1 WF
20	AEP OLIVE 1 SP	75	JC DOMIN LANE 1 SP	130	PL PA SOLAR 1 SP	185	PS MARION SOLAR 1 SP	240	VP WAN - GLOUCESTER 1 SP
21	AEP ORCHARD HILLS 1 LF	76	JC DURBAN AVENUE 1 SP	131	PL TURKEY HILL 1 WF	186	PS MATRIX PA SOLAR 2 SP	241	VP WHITAKERS 1 SP
22	AEP RALEIGH COUNTY 1 LF	77	JC E FLEMINGTON 5 SP	132	PN ALPACA GLORY BARN 1 D	187	PS MAYWOOD SOLAR 1 SP	242	VP WOODBINE ROAD 1 SP
23	AEP TRENT 1 BT	78	JC EAST AMWELL 7 SP	133	PN GARRETT 1 BT	188	PS METRO HQ 2 SP		
24	AEP TWINBRANCH 1 SP	79	JC EGYPT 3 SP	134	PN LAUREL HIGHLANDS 2 LF	189	PS MIDDLESEX 1 SP		
25	AEP ZANESVILLE 2 LF	80	JC FISCHER 8 SP	135	PN MEYERSDALE 2 BT	190	PS MILL CREEK 1 SP		
26	AP BAKER POINT 1 SP	81	JC FOUL RIFT ROAD 1 SP	136	PN MILAN ENERGY 1 D	191	PS MOORESTOWN 1 SP		
27	AP DOUBLE TOLLGATE SP	82	JC FRANKFORD 4 SP	137	PN NORTH MESHOPPEN 1 CT	192	PS MT LAUREL 1 SP		
28	AP HP HOOD 1 CT	83	JC FRANKLIN 7 SP	138	PN OXBOW CREEK ENERGY CENTER 1 D	193	PS NEW MILFORD SOLAR 1 SP		
29	AP LETZBURG - ELK HILL 2 SP	84	JC FREEMALL 1 FC	139	PN WHITETAIL 1 SP	194	PS NEW ROAD 1 SP		
30	AP MAHONING CREEK 1 H	85	JC FRENCHES 2 SP	140	PS ALDENE SOLAR 1 SP	195	PS NEWARK SOLAR 1 SP		
31	AP MT ST MARYS PV PARK 2 SP	86	JC FRENCHTOWN 1 SP	141	PS ATHENIA SOLAR 1 SP	196	PS NEWARK SOLAR 3 SP		
32	AP PINESBURG 1 SP	87	JC FRENCHTOWN 2 SP	142	PS BAYONNE 1 SP	197	PS NIXON LANE 2 SP		
33	AP STATE COLLEGE 1 BT	88	JC FRENCHTOWN 3 SP	143	PS BAYONNE SOLAR 2 SP	198	PS NORTH AMERICAN 4 SP		
34	BC ALPHA RIDGE 1 LF	89	JC HANOVER 2 SP	144	PS BELLEVILLE SOLAR 1 SP	199	PS NORTH AVE SOLAR 1 SP		
35	BC BRIGHTON DAM 1 H	90	JC HARMONY 1 SP	145	PS BENNETTS SOLAR 1 SP	200	PS OWENS CORNING 1 SP		
36	BC KINGSVILLE 1 SP	91	JC HIGH STREET 6 SP	146	PS BLACK ROCK 1 SP	201	PS PARKLANDS 1 SP		
37	BC MILLERSVILLE 1 LF	92	JC HOFFMAN STATION ROAD 2 SP	147	PS BRIDGEWATER SOLAR 2 SP	202	PS PATERSON PLANK ROAD 1 SP		
38	COM COUNTRYSIDE 1 LF	93	JC HOLLAND 4 SP	148	PS CALDWELL PUMP 2 BT	203	PS PENNINGTON 3 BT		
39	COM DIXON LEE 5 LF	94	JC HOLMDEL 9 SP	149	PS CAMPUS DRIVE 2 SP	204	PS PENNINGTON 4 SP		
40	COM GRAND RIDGE 6 BT	95	JC HOWELL 1 SP	150	PS CEDAR GROVE SOLAR 1 SP	205	PS PENNSAUKEN 1 LF		
41	COM MAGID GLOVE 1 BT	96	JC JACOBSTOWN 1 SP	151	PS CEDAR LANE FLORENCE 6 SP	206	PS PENNSAUKEN 3 SP		
42	COM MORRIS 1 LF	97	JC JUNCTION ROAD 6 SP	152	PS COOK ROAD SOLAR 2 SP	207	PS PRINCETON HOSPITAL 1 CT		
43	COM ORCHARD 1 LF	98	JC LAKEHURST 3 SP	153	PS COOPER HOSPITAL 1 BT	208	PS RARITAN CENTER 3 SP		
44	COM SOLBERG 1 BT	99	JC LEBANON 1 SP	154	PS COOPER HOSPITAL 15 SP	209	PS REEVES EAST 3 SP		
45	COM STERLING RAIL 1 BT	100	JC LEGLER LANDFILL 7 SP	155	PS CRANBURY 2 SP	210	PS REEVES SOUTH 1 SP		
46	DEOK BECKJORD 1 BT	101	JC MANALAPAN 1 SP	156	PS CROSSWIC 1 SP	211	PS REEVES WEST 4 SP		
47	DEOK BECKJORD 2 BT	102	JC MILLHURST 3 SP	157	PS CROSSWIC 2 SP	212	PS RIDER UNIVERSITY 3 SP		
48	DEOK BROWN COUNTY 1 LF	103	JC MUDDY FORGE 3 SP	158	PS DEVILSBROOK 1 SP	213	PS RIVER ROAD 2 SP		
49	DEOK CLINTON 1 BT	104	JC NORTH HANOVER 4 SP	159	PS DOREMUS SOLAR 1 SP	214	PS ROSELAND SOLAR 1 SP		
50	DEOK WILLEY 1 BT	105	JC NORTH PARK 1 SP	160	PS E RUTHERFORD SOLAR 1 SP	215	PS SADDLE BROOK SOLAR 1 SP		
51	DPL BLOOM ENERGY 1 FC	106	JC NORTH PARK 2 SP	161	PS EASTAMPTON 1 SP	216	PS SPRINGFIELD SOLAR 1 SP		
52	DPL BUCKTOWN 1 SP	107	JC NORTH RUN 11 SP	162	PS EDISON 1 SP	217	PS SUNNYMEADE SOLAR 1 SP		
53	DPL CHURCH HILL 1 SP	108	JC OLD BRIDGE 1 SP	163	PS ESSEX 105 CT	218	PS TAYLORS LANE 1 SP		
54	DPL COSTEN 1 SP	109	JC PAUCH 3 SP	164	PS FAIRLAWN SOLAR 1 SP	219	PS THOROFARE SOLAR 2 SP		
55	DPL HEBRON 1 SP	110	JC PEMBERTON 1 SP	165	PS FOODBANK 1 SP	220	PS TURNPIKE 1 SP		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and December 31, 2021. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): January 1, 2011 through December 31, 2021

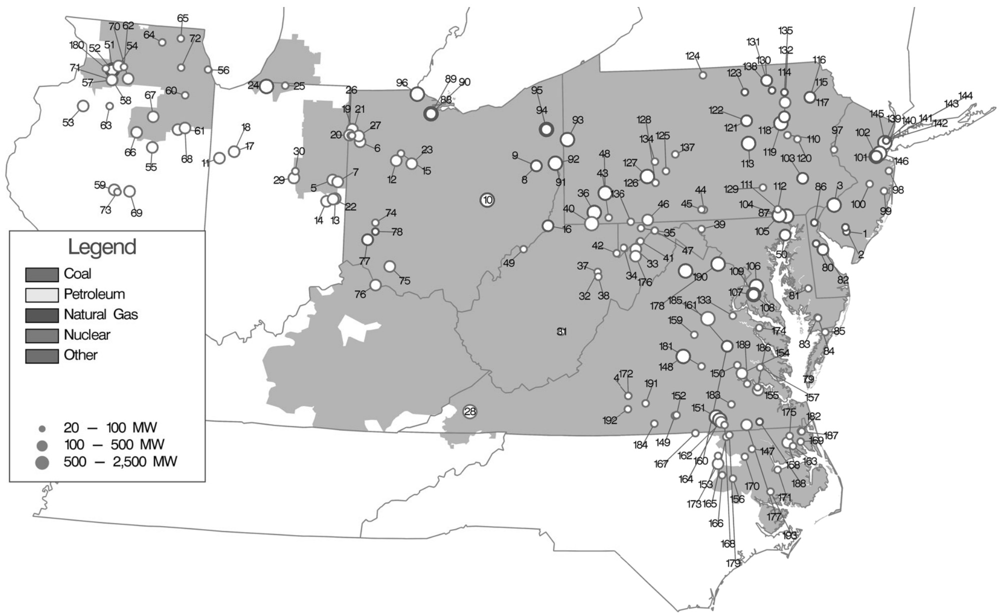


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through December 31, 2021

ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	51	COM 942 NELSON 1 CC	101	JC WOODBRIDGE 1 CC	151	VP BRUNSWICK 1CC
2	ACE VINELAND 11 CT	52	COM 942 NELSON 2 CC	102	JC WOODBRIDGE 2 CC	152	VP BUTCHER CREEK 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	53	COM BISHOP HILL SP in PJM WF	103	ME BIRDSBORO 1 CC	153	VP CHESTNUT 1 SP
4	AEP ALTAVISTA 1 SP	54	COM BLOOMING GROVE 1 WF1	104	PE DELTA 1-4 CC	154	VP CHICKAHOMINY 1 SP
5	AEP BITTER RIDGE 1 WF	55	COM BRIGHT STALK 1 WF	105	PE DELTA 5-7 CC	155	VP COLONIAL TRAIL WEST 1 SP
6	AEP BLUE CREEK 3 WF	56	COM GRAND RIDGE 7 BT	106	PEP KEYS ENERGY CENTER 1 CC	156	VP CONETOE 2 SP
7	AEP BLUFF POINT 2 WF	57	COM GREEN RIVER 1 WF	107	PEP ST CHARLES - KELSON RIDGE 1 CC	157	VP CORRECTIONAL 1 SP
8	AEP CARROLL COUNTY 1 CC	58	COM GREEN RIVER 2 WF	108	PEP ST CHARLES-KELSON RIDGE 1 CC	158	VP DESERT 1 WF
9	AEP CARROLL COUNTY 2 CC	59	COM HILLTOPPER 1 WF	109	PEP ST CHARLES-KELSON RIDGE 2 CC	159	VP DESPER 1 SP
10	AEP DRESDEN 1 CC	60	COM JOLIET 1 BT	110	PL HAZEL 1 FW	160	VP DOSWELL 2 CT
11	AEP FOWLER RIDGE 4 WF	61	COM KELLY CREEK 1 WF	111	PL HOLTWOOD 18	161	VP DOSWELL 3 CT
12	AEP HARDIN 2 SP	62	COM LEE DEKALB 3 BT	112	PL HOLTWOOD 19	162	VP DRY BREAD 1 SP
13	AEP HEADWATERS 1 WF	63	COM LONE TREE 3 WF	113	PL HUMMEL STATION 1 CC	163	VP ELIZABETH CITY 1 SP
14	AEP HEADWATERS 2 WF	64	COM MARENGO 1 BT	114	PL HUNLOCK CC	164	VP GREENSVILLE 1 CC
15	AEP HOG CREEK 1 WF	65	COM MCHENRY 1 BT	115	PL LACKAWANNA COUNTY 1 CC	165	VP GUTENBERG - OCONECHE 1 SP
16	AEP LONG RIDGE ENERGY 1 CC	66	COM MINONK 1 WF	116	PL LACKAWANNA COUNTY 2 CC	166	VP HARTS MILL 1 SP
17	AEP MEADOW LAKE 5 WF	67	COM OTTER CREEK 1 WF	117	PL LACKAWANNA COUNTY 3 CC	167	VP HAWTREE CREEK 1 SP
18	AEP MEADOW LAKE 6 WF	68	COM PILOT HILL 1 WF	118	PL MOXIE FREEDOM 11 CC	168	VP IVORY LANE 1 SP
19	AEP PAULDING 3 WF	69	COM RADFORDS RUN 1 WF	119	PL MOXIE FREEDOM 21 CC	169	VP IVY NECK 2 SP
20	AEP PAULDING 41 WF	70	COM SHADY OAKS 1 WF	120	PL PA SOLAR 2 SP	170	VP KELFORD 1 SP
21	AEP PAULDING 42 WF	71	COM WALNUT RIDGE 1 WF	121	PL PATRIOT 1 F	171	VP MACKEYS 1 SP
22	AEP RIVERSTART 1 SP	72	COM WEST CHICAGO 3 BT	122	PL PATRIOT 2 F	172	VP MECHANICSVILLE 2 SP
23	AEP SCIOTO RIDGE 1 WF	73	COM WHITNEY HILL 2 WF	123	PN BEAVER DAM 1 D	173	VP MOCCASIN CREEK 1 SP
24	AEP ST JOSEPH ENERGY CENTER 1 CC	74	DAY TAIT 8 BT	124	PN BIG LEVEL 1 WF	174	VP MONTROSS 1 SP
25	AEP ST JOSEPH SOLAR PARK 1 SP	75	DEOK HILLCREST 1 SP	125	PN CHESTNUT FLATS 1 WF	175	VP MORGAN CORNER 1 SP
26	AEP TIMBER2 1 WF	76	DEOK MELDAHL DAM 1 H	126	PN FAIRVIEW 1 CC	176	VP NEW CREEK 1 WF
27	AEP TRISHE 1 WF	77	DEOK MIDDLETOWN ENERGY 1 CC	127	PN FAIRVIEW 2 CC	177	VP NEWSOMS 1 SP
28	AEP VIRGINIA CITY 1 F	78	DEOK YANKEE 1 F	128	PN HIGHLAND NORTH 2 WF	178	VP PANDA STONEWALL 1 CC
29	AEP WILDCAT 1A WF	79	DPL CHERRYDALE 1 SP	129	PN LAUREL HILLS 1 WF	179	VP PECAN 1 SP
30	AEP WILDCAT 1B WF	80	DPL DEMEC - CLAYTON 2 CT	130	PN LIBERTY ASYLUM 10 F	180	VP POCATY 1 SP
31	AP BEECH RIDGE 2 WF	81	DPL DORCHESTER COUNTY 1 SP	131	PN LIBERTY ASYLUM 20 F	181	VP POWHATAN 2 SP
32	AP BEECH RIDGE 3 BT	82	DPL GARRISON EC 1 CC	132	PN MEHOOPANY 1 WF	182	VP RANCHLAND 2 SP
33	AP BLACK ROCK 1 WF	83	DPL GREAT BAY KINGS CREEK 1 SP	133	PN MEHOOPANY 2 WF	183	VP SAPONY 1 SP
34	AP FAIR WIND 2 WF	84	DPL GREAT BAY KINGS CREEK 2 SP	134	PN PATTON 1 WF	184	VP SOUTH BOSTON 1 F
35	AP FOURMILE RIDGE 1 WF	85	DPL OAK HALL 1 SP	135	PN PGCOGEN 2 CT	185	VP SPOTSYLVANIA 1 SP
36	AP GREENE COUNTY 1 CC	86	DPL RED LION 1 FC	136	PN RINGER HILL 1 WF	186	VP SPRING GROVE 1 SP
37	AP LAUREL MOUNTAIN 1 BT	87	DPL WILDCAT POINT 1 CC	137	PN SANDY RIDGE 1 WF	187	VP SUMMIT FARMS 1 SP
38	AP LAUREL MOUNTAIN 1 WF	88	FE FREMONT 1 SCCT	138	PN SUGAR RUN 2 CT	188	VP UNION CAMP 9-10 F
39	AP MARLOWE 1 SP	89	FE FREMONT 2 SCCT	139	PS KEARNY 131 CT	189	VP WARDS CREEK 1 SP
40	AP NORTH LONGVIEW 1 F	90	FE FREMONT ENERGY CENTER 3 CC	140	PS KEARNY 132 CT	190	VP WARREN COUNTY FRONT ROYAL CC
41	AP PINNACLE 1 WF	91	FE HIBBETS MILLS ROAD 1 CC	141	PS KEARNY 133 CT	191	VP WATER STRIDER 1 SP
42	AP ROTH ROCK 1 WF	92	FE HIBBETS MILLS ROAD 2 CC	142	PS KEARNY 134 CT	192	VP WHITEHORN 1 SP
43	AP SOUTH CHESTNUT 1 WF	93	FE HICKORY RUN 1 CC	143	PS KEARNY 141 CT	193	VP WILKINSON ENERGY CENTER 1 SP
44	AP ST THOMAS 1 SP	94	FE LORDSTOWN ENERGY CENTER 1 CC	144	PS KEARNY 142 CT		
45	AP ST THOMAS 2 SP	95	FE LORDSTOWN ENERGY CENTER 2 CC	145	PS NEWARK ENERGY CENTER 10 CC		
46	AP TWIN RIDGES 1 WF	96	FE OREGON ENERGY CENTER 1 CC	146	PS SEWAREN 7 CC		
47	AP WARRIOR RUN 2 BT	97	JC EDGE ROAD 5 BT	147	VP AULANDER HOLLOMAN 1 SP		
48	AP WESTMORELAND 1 CC	98	JC HAMILTON ROAD 5 SP	148	VP BEAR GARDEN		
49	AP WILLOW ISLAND 1 H	99	JC OAK RIDGE 3 SP	149	VP BLUESTONE FARM 1 SP		
50	BC PERRYMAN 6 CT	100	JC PLUMSTED ENERGY 6 BT	150	VP BRIEL FARM 1 SP		

Generation Retirements[16][17]

Generating units generally plan to retire when they are not economic and do not expect to be economic. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio.[18] The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions.[19]

Rules that preserve the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the

16 See PJM. Planning. "Generator Deactivations," (Accessed on December 31, 2021) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
17 Generation retirements reported in this section do not include external units. Therefore, retirement totals reported in this section may not match totals reported elsewhere in this report where external units are included.
18 See OATT Part V and Attachment M–Appendix § IV.
19 See PJM. "*Explaining Power Plant Retirements in PJM*," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.

interconnection queue at the same point of interconnection.[20] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. Reforms that require the holders of CIRs to use or lose them, and/or impose costs to holding or transferring them, could make new entry appropriately more attractive. The economic and policy rationale for extending CIRs for inactive units is not clear. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. The policy question of whether CIRs should persist after the retirement of a unit should be addressed. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.

In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[21] The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether CIRs should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[22]

Generation Retirements 2011 through 2024

Table 12-6 shows that as of December 31, 2021, there are 48,406.2 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 37,420.2 MW (77.3 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2024

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,186.5	996.0	148.0	108.0	0.0	0.0	5,542.7
Retirements 2019	0.0	0.0	346.8	51.4	6.4	0.0	0.0	0.0	805.0	0.0	0.0	15.9	0.0	0.0	0.0	4,113.8	97.0	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	786.0	60.0	0.0	0.0	3,255.0
Retirements 2021	4.0	118.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.4	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,307.8
Planned Retirements (January 2022 and later)	40.0	240.5	150.6	284.3	0.0	0.0	0.0	0.0	0.0	0.0	21.0	2.5	0.0	0.0	0.0	6,342.1	0.0	0.0	0.0	0.0	0.0	7,081.0
Total	85.0	783.5	2,434.9	2,109.2	22.0	0.0	0.5	0.0	1,419.5	0.0	65.1	80.4	0.0	0.0	0.0	37,420.2	2,065.5	1,658.0	252.0	10.4	0.0	48,406.2

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2024, while Table 12-8 shows these retirements by state. Of the 48,406.2 MW of units that has been, or are planned to be, retired between 2011 and 2024, 37,420.2 MW (77.3 percent) are coal fired steam units. These coal fired steam units have an average age of 52.4 years and an average size of 206.7 MW. Over half of the retiring coal fired steam units, 54.6 percent, are located in Ohio or Pennsylvania.

20 See OATT § 230.3.3.
21 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
22 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Table 12-7 Retirements by unit type: 2011 through 2024

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	6	14.2	6.1	85.0	0.2%
Combined Cycle	6	130.6	29.1	783.5	1.6%
Combustion Turbine	131	25.4	35.6	4,566.1	9.4%
Natural Gas	64	38.0	41.5	2,434.9	5.0%
Oil	61	34.6	46.0	2,109.2	4.4%
Other	6	3.7	19.2	22.0	0.0%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	2	709.8	47.2	1,419.5	2.9%
RICE	35	4.3	25.5	145.5	0.3%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	14	4.7	39.6	65.1	0.1%
Other	21	3.8	11.4	80.4	0.2%
Solar	0	0	0	0	0.0%
Solar + Storage	0	0	0	0	0.0%
Solar + Wind	0	0	0	0	0.0%
Steam	213	157.3	45.7	41,395.7	85.5%
Coal	181	206.7	52.4	37,420.2	77.3%
Natural Gas	18	114.8	60.8	2,065.5	4.3%
Oil	6	276.3	45.6	1,658.0	3.4%
Other	8	31.5	23.8	252.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0	0	0	0.0%
Total	395	122.5	45.2	48,406.2	100.0%

Table 12-8 Retirements (MW) by unit type and state: 2011 through 2024

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	664.0	136.0	0.0	0.0	0.0	0.0	800.0
IL	40.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.4	0.0	0.0	0.0	2,818.1	0.0	0.0	0.0	0.0	0.0	3,174.5
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	104.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	0.0	3,068.0	171.0	0.0	0.0	0.0	0.0	3,695.3
NC	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	0.0	355.5
NJ	0.0	465.5	1,590.0	1,040.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	22.5	0.0	0.0	0.0	1,543.0	932.5	148.0	10.0	0.0	0.0	6,381.1
OH	42.0	0.0	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	19.3	5.4	0.0	0.0	0.0	15,117.4	0.0	0.0	0.0	0.0	0.0	15,491.1
PA	1.0	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	13.9	20.5	0.0	0.0	0.0	5,299.3	283.0	176.0	109.0	10.4	0.0	7,211.8
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	23.9	8.4	0.0	0.0	0.0	3,917.9	543.0	786.0	83.0	0.0	0.0	5,788.9
WV	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,691.0	0.0	0.0	0.0	0.0	0.0	2,693.0
Total	85.0	783.5	2,434.9	2,109.2	22.0	0.0	0.5	0.0	1,419.5	0.0	65.1	80.4	0.0	0.0	0.0	37,420.2	2,065.5	1,658.0	252.0	10.4	0.0	48,406.2

Figure 12-4 is a map of unit retirements between 2011 and 2024, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2024

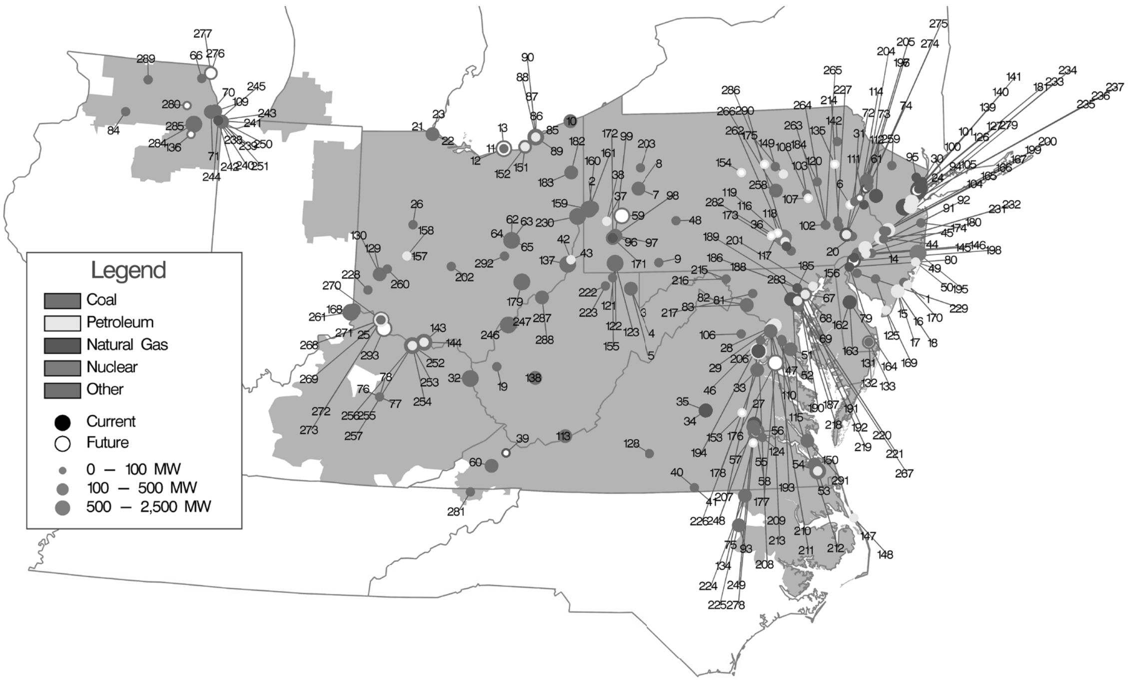


Table 12-9 Unit identification for map of unit retirements: 2011 through 2024

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Columbia Dam Hydro	121	Hatfield's Ferry 1	181	New Bay Cogen CC	241	Southeast Chicago CT6
2	AES Beaver Valley	62	Conesville 3	122	Hatfield's Ferry 2	182	Niles 1	242	Southeast Chicago CT7
3	Albright 1	63	Conesville 4	123	Hatfield's Ferry 3	183	Niles 2	243	Southeast Chicago CT8
4	Albright 2	64	Conesville 5	124	Hopewell James River Cogeneration	184	Northeastern Power NEPCO	244	Southeast Chicago GT10
5	Albright 3	65	Conesville 6	125	Howard Down 10	185	Notch Cliff GT1	245	Southeast Chicago GT9
6	Allentown CT 1-4	66	Countryside Landfill	126	Hudson 1	186	Notch Cliff GT2	246	Sporn 1-4
7	Armstrong 1	67	Crane 1	127	Hudson 2	187	Notch Cliff GT3	247	Sporn 5
8	Armstrong 2	68	Crane 2	128	Hurt NUG	188	Notch Cliff GT4	248	Spruance NUG1 (Rich 1-2)
9	Arnold (Green Mtn. Wind Farm	69	Crane GT1	129	Hutchings 1-3, 5-6	189	Notch Cliff GT5	249	Spruance NUG2 (Rich 3-4)
10	Ashtabula 5	70	Crawford 7	130	Hutchings 4	190	Notch Cliff GT6	250	State Line 3
11	Avon Lake 10	71	Crawford 8	131	Indian River 1	191	Notch Cliff GT7	251	State Line 4
12	Avon Lake 7	72	Cromby 1	132	Indian River 3	192	Notch Cliff GT8	252	Stuart 1
13	Avon Lake 9	73	Cromby 2	133	Indian River 4	193	Oaks Landfill	253	Stuart 2
14	BC Landfill	74	Cromby D	134	Ingenco Petersburg	194	Occoquan 1 LF	254	Stuart 3
15	BL England 1	75	DINWIDDIE 1 CT	135	Jenkins CT 1-2	195	Oyster Creek	255	Stuart 4
16	BL England 2	76	Dale 1-2	136	Joliet Energy Storage	196	PL MARTINS CREEK 1-4 CT	256	Stuart Diesels 1-4
17	BL England 3	77	Dale 3	137	Kammer 1-3	197	PL MARTINS CREEK 1-4 CT	257	Stuart Diesels 1-4
18	BL England Diesel Units 1-4	78	Dale 4	138	Kanawha River 1-2	198	Pedricktown Cogen CC	258	Sunbury 1-4
19	Balls Gap Battery Facility	79	Deepwater 1	139	Kearny 10	199	Pennsbury Generator Landfill 1	259	Sussex County LF
20	Barbados AES Battery	80	Deepwater 6	140	Kearny 11	200	Pennsbury Generator Landfill 2	260	Tait Battery
21	Bay Shore 2	81	Dickerson Unit 1	141	Kearny 9	201	Perryman 2	261	Tanners Creek 1-4
22	Bay Shore 3	82	Dickerson Unit 2	142	Keystone Recovery (Units 1 - 7)	202	Picway 5	262	Three Mile Island Unit 1
23	Bay Shore 4	83	Dickerson Unit 3	143	Killen 2	203	Piney Creek NUG	263	Titus 1
24	Bayonne Cogen Plant (CC)	84	Dixon Lee Landfill Generator	144	Killen CT	204	Portland 1	264	Titus 2
25	Beckjord Battery Unit 2	85	Eastlake 1	145	Kimberly Clark Generator	205	Portland 2	265	Titus 3
26	Bellefontaine Landfill Generating Station	86	Eastlake 2	146	Kinsley Landfill	206	Possum Point 3	266	Viking Energy NUG
27	Bellemeade	87	Eastlake 3	147	Kitty Hawk GT 1	207	Possum Point 4	267	Wagner 2
28	Benning 15	88	Eastlake 4	148	Kitty Hawk GT 2	208	Possum Point 5	268	Walter C Beckjord 1
29	Benning 16	89	Eastlake 5	149	Koppers Co. IPP	209	Potomac River 1	269	Walter C Beckjord 2
30	Bergen 3	90	Eastlake 6	150	Lake Kingman	210	Potomac River 2	270	Walter C Beckjord 3
31	Bethlehem Renewable Energy Generator (Landfill)	91	Eddystone 1	151	Lake Shore 18	211	Potomac River 3	271	Walter C Beckjord 4
32	Big Sandy 2	92	Eddystone 2	152	Lake Shore EMD	212	Potomac River 4	272	Walter C Beckjord 5-6
33	Birchwood Plant	93	Edgecomb NUG (Rocky 1-2)	153	Lanier 1 CT	213	Potomac River 5	273	Walter C Beckjord GT 1-4
34	Bremo 3	94	Edison 1-3	154	Lock Haven CT 1	214	Pottstown LF (Moser)	274	Warren County Landfill
35	Bremo 4	95	Elmwood Park Power	155	MEA NUG (WVU)	215	R Paul Smith 3	275	Warren County NUG
36	Brunner Island Diesels	96	Elrama 1	156	MH50 Markus Hook Co-gen	216	R Paul Smith 4	276	Waukegan 7
37	Brunot Island 1B	97	Elrama 2	157	Mad River CTs A	217	Reichs Ford Road Landfill Generator	277	Waukegan 8
38	Brunot Island 1C	98	Elrama 3	158	Mad River CTs B	218	Riverside 4	278	Weakley CT
39	Buchanan 1-2	99	Elrama 4	159	Mansfield 1	219	Riverside 6	279	Werner 1-4
40	Buggs Island 1 (Mecklenberg)	100	Essex 10-11	160	Mansfield 2	220	Riverside 7	280	West Chicago Energy Storage
41	Buggs Island 2 (Mecklenberg)	101	Essex 12	161	Mansfield 3	221	Riverside 8	281	West Kingsport LF
42	Burger 3	102	Evergreen Power United Corstack	162	McKee 1	222	Riversville 5	282	West Shore CT 1-2
43	Burger EMD	103	FRACKVILLE WHEELABRATOR 1	163	McKee 2	223	Riversville 6	283	Westport 5
44	Burlington 8,11	104	Fairless Hills Landfill A	164	McKee 3	224	Roanoke Valley 1	284	Will County 3
45	Burlington 9	105	Fairless Hills Landfill B	165	Mercer 1	225	Roanoke Valley 2	285	Will County 4
46	Buzzard Point East Banks 1,2,4-8	106	Fauquier County Landfill	166	Mercer 2	226	Rockville CT	286	Williamsport-Lycoming CT 1-2
47	Buzzard Point West Banks 1-9	107	Fishbach CT 1	167	Mercer 3	227	Rolling Hills Landfill Generator	287	Willow Island 1
48	Cambria CoGen	108	Fishbach CT 2	168	Miami Fort 6	228	SMART Paper	288	Willow Island 2
49	Cedar 1	109	Fisk Street 19	169	Middle 1-3	229	Salem County LF	289	Winnebago Landfill
50	Cedar 2	110	GUDE Landfill	170	Missouri Ave B,C,D	230	Sammis 1-4	290	York Generation Facility
51	Chalk Point Unit 1	111	Gilbert 1-4	171	Mitchell 2	231	Schuylkill 1	291	Yorktown 1-2
52	Chalk Point Unit 2	112	Glen Gardner 1-8	172	Mitchell 3	232	Schuylkill Diesel	292	Zanesville Landfill
53	Chesapeake 1-4	113	Glen Lyn 5-6	173	Modern Power Landfill NUG	233	Sewaren 1	293	Zimmer 1
54	Chesapeake 7-10	114	Glendon LF	174	Monmouth NUG landfill	234	Sewaren 2		
55	Chesterfield 3	115	Gould Street Generation Station	175	Montour ATG	235	Sewaren 3		
56	Chesterfield 4	116	Harrisburg 4 CT	176	Morgantown Unit 1	236	Sewaren 4		
57	Chesterfield 5	117	Harrisburg CT 1	177	Morgantown Unit 2	237	Sewaren 6		
58	Chesterfield 6	118	Harrisburg CT 2	178	Morris Landfill Generator	238	Southeast Chicago CT11		
59	Cheswick 1	119	Harrisburg CT 3	179	Muskingum River 1-5	239	Southeast Chicago CT12		
60	Clinch River 3	120	Harwood 1-2	180	National Park 1	240	Southeast Chicago CT5		

Current Year Generation Retirements

Table 12-10 shows that in 2021, 1,307.8 MW of generation retired. The largest generators that retired in 2021 were the 667.0 MW Chalk Point Unit 1 and 2 coal fired steam units located in the PEPCO Zone. Of the 1,307.8 MW of generation that retired, 669.4 MW (51.2 percent) were located in the PEPCO Zone.

Table 12-10 Unit deactivations: 2021

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Ares Management LP	Spruance NUG1 (aka Spruance 1 Rich 1-2)	115.5	Steam-Coal	DOM	28.7	12-Jan-21
Biogas Energy Solutions, LLC	Countryside Landfill	8.0	RICE-Other	COMED	8.5	27-Jan-21
Galt Power Inc.	Beckjord Battery Unit 2	2.0	Battery	DUKE	5.3	03-Feb-21
General Electric Company	Birchwood Plant	237.9	Steam-Coal	DOM	24.3	01-Mar-21
Riverstone Holdings LLC	Elmwood Park Power	67.0	Combined Cycle	PSEG	32.0	12-Mar-21
American Electric Power Company, Inc.	Balls Gap Battery Facility	2.0	Battery	AEP	4.2	22-Apr-21
Domtar Corporation	West Kingsport LF	50.0	Steam-Other	AEP	14.7	31-May-21
City of Dover	McKee 3	102.0	Steam-Natural Gas	DPL	46.1	01-Jun-21
GenOn Energy, Inc.	Chalk Point Unit 1	331.0	Steam-Coal	PEPCO	56.9	01-Jun-21
GenOn Energy, Inc.	Chalk Point Unit 2	336.0	Steam-Coal	PEPCO	56.3	01-Jun-21
Northeast Maryland Waste Disposal Authority	Oaks Landfill	2.4	RICE-Other	PEPCO	12.5	01-Jul-21
Riverstone Holdings LLC	York Generation Facility	51.0	Combined Cycle	MEC	32.7	20-Sep-21
South Jersey Industries, Inc.	AC Landfill Units 1 and 2	3.0	RICE-Other	ACEC	15.2	01-Oct-21
Total		1,307.8				

Planned Generation Retirements

Table 12-11 shows that, as of December 31, 2021, there are 7,081.0 MW of generation that have requested retirement after December 31, 2021. Of the 7,081.0 MW requesting retirement, 6,342.1 MW (89.6 percent) are coal fired steam units. As of December 31, 2021, there are planned coal fired unit retirements in seven different PJM zones. Of the 7,081.1 MW of planned retirements, 1,300.0 MW (18.4 percent) are located in the DUKE Zone. Of the generation requesting retirement in the DUKE Zone, 1,300.0 MW (100.0 percent) are coal fired steam units.

Table 12-11 Planned retirement of units: December 31, 2021

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Renewable Energy Systems Holdings LTD	Joliet Energy Storage	20.0	Battery	COMED	08-Feb-22
Renewable Energy Systems Holdings LTD	West Chicago Energy Storage	20.0	Battery	COMED	08-Feb-22
GenOn Energy, Inc.	Avon Lake 10	21.0	CT-Oil	ATSI	01-Apr-22
GenOn Energy, Inc.	Avon Lake 9	638.0	Steam-Coal	ATSI	01-Apr-22
GenOn Energy, Inc.	Cheswick 1	565.0	Steam-Coal	DUQ	01-Apr-22
Riverstone Holdings LLC	Fishbach CT 1	28.0	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Fishbach CT 2	14.0	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Jenkins CT 1-2	27.6	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Lock Haven CT 1	14.0	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	West Shore CT 1	28.0	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Williamsport-Lycoming CT 1-2	26.6	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Harwood 1-2	28.0	CT-Oil	PPL	31-May-22
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	31-May-22
Riverstone Holdings LLC	Martins Creek CT 4	17.3	CT-Natural_Gas	PPL	31-May-22
GenOn Energy, Inc.	Morgantown Unit 1	610.0	Steam-Coal	PEPCO	31-May-22
GenOn Energy, Inc.	Morgantown Unit 2	619.0	Steam-Coal	PEPCO	31-May-22
Riverstone Holdings LLC	New Bay Cogen CC	120.2	Combined Cycle	PSEG	31-May-22
Riverstone Holdings LLC	Pedricktown Cogen CC	120.3	Combined Cycle	ACEC	31-May-22
NRG Energy Inc	Waukegan 7	328.0	Steam-Coal	COMED	31-May-22
NRG Energy Inc	Waukegan 8	356.1	Steam-Coal	COMED	31-May-22
NRG Energy Inc	Will County 4	510.0	Steam-Coal	COMED	31-May-22
American Electric Power Company, Inc.	Zimmer 1	330.0	Steam-Coal	DUKE	31-May-22
The AES Corporation	Zimmer 1	365.0	Steam-Coal	DUKE	31-May-22
Vistra Energy Corp	Zimmer 1	605.0	Steam-Coal	DUKE	31-May-22
Riverstone Holdings LLC	Allentown CT 1-4	56.0	CT-Oil	PPL	01-Jun-22
Energy Power Investment Company, LLC	Glendon LF	2.5	RICE-Other	MEC	01-Jun-22
Riverstone Holdings LLC	Harrisburg CT 1	13.4	CT-Oil	PPL	01-Jun-22
Riverstone Holdings LLC	Harrisburg CT 2	13.9	CT-Oil	PPL	01-Jun-22
Riverstone Holdings LLC	Harrisburg CT 3	13.8	CT-Oil	PPL	01-Jun-22
Riverstone Holdings LLC	Martins Creek CT 1	18.0	CT-Natural_Gas	PPL	01-Jun-22
Riverstone Holdings LLC	Martins Creek CT 2	17.3	CT-Natural_Gas	PPL	01-Jun-22
Riverstone Holdings LLC	Martins Creek CT 3	18.0	CT-Natural_Gas	PPL	01-Jun-22
Dominion Energy, Inc.	Chesterfield 5	336.0	Steam-Coal	DOM	31-May-23
Dominion Energy, Inc.	Chesterfield 6	670.0	Steam-Coal	DOM	31-May-23
LS Power Equity Partners, L.P.	Buchanan 1-2	80.0	CT-Natural_Gas	AEP	01-Jun-23
Castleton Commodities International LLC	DINWIDDIE 1 CT	3.0	RICE-Oil	DOM	01-Jun-23
Castleton Commodities International LLC	Lanier 1 CT	7.0	RICE-Oil	DOM	01-Jun-23
Castleton Commodities International LLC	Rockville CT	4.0	RICE-Oil	DOM	01-Jun-23
Castleton Commodities International LLC	Weakley CT	7.0	RICE-Oil	DOM	01-Jun-23
Total		7,081.0			

Generation Queue[23]

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[24] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants. But the behavior of project developers also creates issues with queue management and exacerbates the barriers.

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. Queues A and B were open for one year. Queues C through T were open for six months. Starting in February 2008, Queues U through Y1 were open for three months. In May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AG2 opened on October 1, 2020 and closed on March 31, 2021, Queue AH1 opened on April 1, 2021 and closed on September 10, 2021and Queue AH2 opened on October 1, 2021. On June 24, 2021, PJM requested tariff modifications to close queue windows on September 10 and March 10, rather than September 30 and March 31.[25] This change allows more time to review the new requests to the queue without shortening the amount of time available for the resulting model builds and analyses. On August 23, 2021, the Commission approved the tariff modifications.[26]

Projects submitted to the queue undergo a deficiency review to ensure that all required information is provided. If a project is missing information, or if the submitting developer owes money from a prior queue request, the submission is defined to be deficient. PJM was required to perform the review and provide notification within five business days of receipt of the request. The developer had ten business days to respond. PJM had five business days to review the response. As a result of the large number of project submissions submitted close to the end of each queue window, PJM could not meet the required timeline. On June 24, 2021, PJM filed tariff changes to modify the deficiency review timeline.[27] PJM requested an increase in the initial notification to the interconnection customer from five to 15 business days, or as soon thereafter as practicable, making the deadline flexible. The developer has ten business days to respond. PJM requested an increase in PJM's time to respond from five to 15 business days, or as soon thereafter as practicable, making the deadline flexible. On August 23, 2021, the Commission approved the tariff modifications.[28] A queue position is assigned once the project has met the submission requirements. Projects that do not meet submission requirements are removed from the queue.

All projects that have entered a queue and have met the submission requirements have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in service. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years. Projects that entered the queue after February 1, 2011, face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[29] When a project is suspended, PJM extends the scheduled milestones by the duration of the suspension. If, at any time, a milestone is not met, PJM will initiate the termination of the Interconnection Service Agreement (ISA) and the corresponding cancellation costs must be paid by the customer.[30]

PJM has generally met the deadlines for feasibility and system impact studies. The increase in the number of projects submitted have contributed to a significant backlog in performing timely facility studies. The facility study includes the conceptual design, stability analyses

23 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
24 See OATT Parts IV & VI.
25 See PJM Filing, Docket ER21-2203 (June 24, 2021).
26 176 FERC ¶ 61,117 (2021).
27 See PJM Filing, Docket ER21-2203 (June 24, 2021).
28 176 FERC ¶ 61,117 (2021).
29 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 14 (January 27, 2021).
30 PJM does not track the duration of suspensions or PJM termination of projects.

and determines the network upgrades, and the costs associated with those upgrades. Modifications to proposed facilities and restudies resulting from the withdrawal of projects from the queue also affect the time to complete a facility study. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created.

In 2020, PJM conducted interconnection process workshops designed to review current processes, receive input and recommendations from stakeholders and to develop improvements to the process, resulting in the creation of the Interconnection Process Reform Task Force (IPRTF) to improve overall queue management. Proposals in the IPRTF include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation.

The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Some project developers enter speculative projects in the queue and then put the project in suspended status.

On July 15, 2021, the Commission issued an Advance Notice of Proposed Rulemaking (ANOPR).[31] The purpose of the ANOPR is to review transmission related regulations and determine whether additional reforms to the regional transmission planning, cost allocation and generator interconnection processes are needed. The ANOPR discusses the impacts of transmission rules on the competitiveness of the energy markets but does not focus on the competitiveness of transmission itself. Given that the cost of transmission is increasing as a share of total wholesale power costs and now exceeds the cost of capacity in PJM, the cost effectiveness and competitiveness of the transmission planning and procurement process should be addressed when considering reforms.

The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.

Interconnection Process Studies and Agreements[32]

In the study stage of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-12 is an overview of the studies PJM perform in the study stage of the interconnection process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

Table 12-12 Interconnection planning process: Study Stage

Study	Purpose
Feasibility Study	The feasibility study determines preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.
System Impact Study	The system impact study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system. The study identifies the system constraints related to the project and the necessary attachment facilities, local upgrades, and network upgrades. The study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.
Facilities Study	In the facilities study, stability analysis is performed and the system impact study results are modified as necessary to reflect changes in the characteristics of other projects in the queue.

In 2016, the PJM Earlier Queue Submitted Task Force stakeholder group made changes to the interconnection process to address some of the issues related to delays observed in the various stages of the study phase. The changes became effective with the AC2 Queue that closed on March 31, 2017. The MMU recommends continuing analysis of the

31 See *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Advanced Notice of Proposed Rulemaking*, 176 FERC ¶ 61,024 (July 15, 2021).
32 See "PJM Manual 14A: New Services Request Process," Rev. 29 (August 24, 2021) for a complete explanation of the interconnection process studies and agreements.

study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.

In addition to the feasibility, system impact and facilities studies, PJM may also perform additional studies under certain circumstances. These studies include the affected systems study, interim deliverability study and the long term firm transmission studies. Table 12-13 is an overview of the additional studies PJM may perform.

Table 12-13 Interconnection planning process: Study Stage – Additional Studies

Study	Purpose
Affected System Study	PJM and its neighboring balancing authorities conduct interconnection studies to determine the impacts of interconnection requests on the neighboring transmission system.
Interim Deliverability Studies	Interim deliverability studies are conducted on a periodic basis in support of RPM auctions and other interconnection studies to determine if a new facility may come on line prior to its scheduled date. These studies evaluate the available system capability and provide the customer(s) with the availability of service by planning year. Interim deliverability studies use the same criteria used for the evaluation of the need for reinforcements associated with a project under study.
Long Term Firm Transmission Studies	Transmission service requests that extend beyond the available transfer capability horizon of 18 months are evaluated along with the other requests for service in the PJM new services queue to ensure deliverability. Long term firm transmission studies follow the same feasibility, system impact and facilities study process as new generation.

After the completion of a facility study, the project will enter the construction stage of the interconnection process. The final agreements required depend on the type of project. These agreements include a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), Wholesale Market Participant Agreement (WMPA) or Transmission Service Agreement (TSA). Table 12-14 is an overview of the agreements in the construction stage of the interconnection process.

Table 12-14 Interconnection planning process: construction stage agreements

Agreement	Purpose
Interconnection Service Agreement (ISA)	An ISA defines the generation or transmission developer's cost responsibility for required system upgrades. For generation interconnection customers, the ISA defines the capacity interconnection rights for a capacity resource and any operational restrictions or other limitations. For transmission interconnection customers, the ISA defines transmission injection and withdrawal rights and applicable incremental delivery, available transfer capability revenue and auction revenue rights.
Interim Interconnection Service Agreements (I-ISA)	If a developer wishes to start project construction activities prior to completion of the generation or transmission interconnection facilities study, the interim ISA would commit the developer to pay all costs incurred for the construction activities being advanced.
Interconnection Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets. On December 31, 2021, 254,914.6 MW were in generation request queues for construction through 2029. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[33]

33 See "*PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years,*" <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf>.

There were 173,182.4 MW in generation queues, in the status of active, under construction or suspended, at the end of 2020. In 2021, the AG2 and AH1 queue windows closed and the AH2 window opened. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On December 31, 2021, there were 254,914.6 MW in generation queues, in the status of active, under construction or suspended, an increase of 81,732.2 MW (47.2 percent) from December 31, 2020. Table 12-15 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2020, and December 31, 2021, for ongoing projects, i.e. projects with the status active, under construction or suspended.[34]

Table 12-15 Queue comparison by expected completion year (MW): December 31, 2020 and December 31, 2021[35]

			Year Change	
Year	As of 12/31/2020	As of 12/31/2021	MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	0.0	0.0	0.0	0.0%
2012	16.1	0.0	(16.1)	(100.0%)
2013	20.0	20.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	0.0	0.0	0.0	0.0%
2016	19.4	3.4	(16.0)	(82.5%)
2017	648.1	404.3	(243.8)	(37.6%)
2018	1,825.6	668.6	(1,157.0)	(63.4%)
2019	7,153.5	5,093.3	(2,060.2)	(28.8%)
2020	10,601.5	7,297.0	(3,304.4)	(31.2%)
2021	27,958.0	25,991.2	(1,966.8)	(7.0%)
2022	39,526.5	42,802.2	3,275.7	8.3%
2023	38,138.0	57,051.8	18,913.8	49.6%
2024	19,227.5	60,472.9	41,245.4	214.5%
2025	3,990.6	35,665.6	31,675.0	793.7%
2026	2,645.2	8,636.2	5,991.0	226.5%
2027	2,100.1	5,840.1	3,740.0	178.1%
2028	0.0	2,508.0	2,508.0	0.0%
2029	800.1	2,460.1	1,660.0	207.5%
Total	154,670.1	254,914.6	100,244.5	64.8%

Table 12-16 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2020, and December 31, 2021. For example, 105,287.0 MW entered the queue in 2021. Of those 105,287.0 MW, 5,042.5 MW have been withdrawn. Of the total 156,386.7 MW marked as active on December 31, 2020, 13,027.3 MW were withdrawn, 5,004.4 MW were suspended, 2,293.0 MW started construction, and 557.5 MW went into service by December 31, 2021. Analysis of projects that were suspended on December 31, 2020 show that 946.0 MW came out of suspension and are now active as of December 31, 2021.

Table 12-16 Change in project status (MW): December 31, 2020 to December 31, 2021

		Status at 12/31/2021				
Status at 12/31/2020	Total at 12/31/2020	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2021)	0.0	100,244.5	0.0	0.0	0.0	5,042.5
Active	156,386.7	135,504.5	557.5	2,293.0	5,004.4	13,027.3
In Service	72,723.3	0.0	72,721.2	0.0	0.0	2.1
Under Construction	9,570.7	12.1	3,233.1	6,303.6	0.0	21.9
Suspended	7,017.3	946.0	0.0	400.0	4,116.5	1,554.8
Withdrawn	410,672.5	90.0	0.0	0.0	0.0	410,582.5
Total	656,370.5	236,797.1	76,511.8	8,996.6	9,120.9	430,231.1

34 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
35 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

On December 31, 2021, 254,914.6 MW were in generation request queues in the status of active, suspended or under construction. Table 12-17 shows each status by unit type. Of the 236,797.1 MW in the status of Active on December 31, 2021, 7,198.3 MW (3.0 percent) were combined cycle projects. Of the 8,996.6 MW in the status of under construction, 6,023.6 MW (67.0 percent) were combined cycle projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 236,797.1 MW in the status of Active on December 31, 2021, 31,703.9 MW (13.4 percent) were renewable hybrid projects. Of the 8,996.6 MW in the status of under construction, 5.7 MW (.006 percent) were renewable hybrid projects.

Table 12-17 Current project status (MW) by unit type: December 31, 2021

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	38,267.5	7,198.3	3,975.3	4.0	396.6	5.0	730.0	124.9	145.5	14.4	0.0	0.0	115,049.7	31,494.9	209.0	40.0	11.0	0.0	20.0	39,111.1	0.0	236,797.1
Suspended	34.0	5,486.0	1,518.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,481.0	128.0	0.0	0.0	0.0	0.0	0.0	367.6	106.3	9,120.9
Under Construction	0.0	6,023.6	335.0	13.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	2,426.3	5.7	0.0	36.0	0.0	0.0	0.0	110.0	0.0	8,996.6
Total	38,301.5	18,707.9	5,828.3	17.0	396.6	8.0	730.0	124.9	189.5	14.4	0.0	0.0	118,957.0	31,628.6	209.0	76.0	11.0	0.0	20.0	39,588.7	106.3	254,914.6

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units and renewable, hybrid and other intermittent resources enter the queue and coal fired steam units retire. As of December 31, 2021, of the 254,914.6 MW in the generation request queues in the status of active, suspended or under construction, 118,957.0 (46.7 percent) were solar projects, 39,588.7 MW (15.5 percent) were wind projects, 24,561.6 MW (9.6 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 31,943.9 MW (12.5 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 76.0 MW (0.03 percent) were coal fired steam projects.

As of December 31, 2021, there are 6,342.1 MW of coal fired steam units and 150.6 MW of natural gas units slated for deactivation between January 1, 2022, and December 31, 2024 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure. The small but growing level of renewables, hybrids and other intermittents will also have increasingly significant impacts on the energy and capacity markets.

Table 12-18 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total MW that had been included in each queue. All items in queues A-R are either in service or have been withdrawn. As of December 31, 2021, there are 254,914.6 MW in queues that are not yet in service or withdrawn, of which 3.6 percent are suspended, 3.5 percent are under construction and 92.9 percent have not begun construction.

Table 12-18 Queue totals by status (MW): December 31, 2021[36]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,094.0	0.0	0.0	17,252.0	26,346.0
B Expired 31-Jan-99	0.0	4,292.4	0.0	0.0	14,958.8	19,251.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,171.6	0.0	0.0	17,961.8	19,133.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	0.0	0.0	8,129.3	10,528.0
O Expired 31-Jul-05	0.0	1,890.2	0.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,290.3	0.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,892.5	0.0	0.0	20,708.9	22,601.4
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	4,196.5	0.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	777.5	0.0	0.0	16,218.6	16,996.1
U3 Expired 31-Oct-08	0.0	333.0	0.0	100.0	2,535.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	0.0	4,945.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	16.1	0.0	3,625.1	4,631.1
V3 Expired 31-Oct-09	0.0	1,132.0	0.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	0.0	3,708.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	12.1	508.7	0.0	0.0	8,683.8	9,204.6
W4 Expired 31-Jan-11	0.0	1,415.8	0.0	0.0	4,152.6	5,568.4
X1 Expired 30-Apr-11	0.0	1,103.8	0.0	0.0	6,200.6	7,304.4
X2 Expired 31-Jul-11	0.0	3,706.4	0.0	0.0	5,578.4	9,284.7
X3 Expired 31-Oct-11	0.0	89.2	20.0	0.0	7,665.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	0.0	1,795.5	0.0	0.0	6,279.7	8,075.2
Y2 Expired 31-Oct-12	0.0	1,657.2	0.0	0.0	9,636.5	11,293.7
Y3 Expired 30-Apr-13	0.0	1,425.5	205.0	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	38.0	3,074.5	0.0	975.3	4,037.0	8,124.8
Z2 Expired 30-Apr-14	0.0	3,063.0	0.0	10.0	3,027.8	6,100.8
AA1 Expired 31-Oct-14	278.6	4,678.9	150.0	463.0	6,498.4	12,068.9
AA2 Expired 30-Apr-15	682.0	1,825.6	995.0	1,091.0	11,472.7	16,066.3
AB1 Expired 31-Oct-15	2,706.8	1,430.9	1,275.8	3,106.0	11,924.3	20,443.7
AB2 Expired 31-Mar-16	1,226.8	1,142.3	2,092.3	557.0	10,147.4	15,165.8
AC1 Expired 30-Sep-16	2,680.5	1,114.6	3,569.8	1,538.6	11,138.9	20,042.2
AC2 Expired 30-Apr-17	2,502.4	530.1	66.4	364.9	9,137.8	12,601.6
AD1 Expired 30-Sep-17	5,316.4	298.9	106.6	305.0	5,275.7	11,302.6
AD2 Expired 31-Mar-18	6,069.4	310.5	425.8	223.0	13,337.5	20,366.1
AE1 Expired 30-Sep-18	15,168.7	70.5	19.9	47.6	18,600.1	33,906.9
AE2 Expired 31-Mar-19	22,322.8	50.0	3.8	140.4	11,301.9	33,818.8
AF1 Expired 30-Sep-19	21,214.9	16.8	47.0	125.9	7,513.4	28,917.9
AF2 Expired 31-Mar-20	20,928.1	3.0	3.2	48.3	7,226.6	28,209.1
AG1 Expired 30-Sep-20	32,502.6	0.5	0.0	25.0	5,446.5	37,974.6
AG2 Expired 31-Mar-21	55,630.0	0.0	0.0	0.0	1,105.3	56,735.3
AH1 Expired 30-Sep-21	45,764.2	0.0	0.0	0.0	4,030.3	49,794.5
AH2 Opened 01-Oct-21	1,682.9	0.0	0.0	0.0	81.9	1,764.8
Total	236,797.1	76,511.8	8,996.6	9,120.9	430,231.1	761,657.5

36 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Table 12-19 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of December 31, 2021, 254,914.6 MW were in generation request queues for construction through 2029. Table 12-19 also shows the planned retirements for each zone.

Table 12-19 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): December 31, 2021[37]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	1,218.0	7.6	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	678.6	213.0	0.0	0.0	0.0	0.0	0.0	3,441.6	0.0	5,788.8	120.3
	DPL	694.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,319.9	170.0	0.0	0.0	0.0	0.0	0.0	7,671.5	0.0	11,306.4	410.0
	JCPLC	813.8	35.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	472.3	180.0	0.0	0.0	0.0	0.0	0.0	6,589.2	0.0	8,120.3	0.0
	PECO	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	108.3	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	162.3	0.0
	PSEG	1,467.0	51.1	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.4	22.6	0.0	0.0	5.0	0.0	0.0	1,300.0	0.0	3,583.1	120.2
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	4,192.8	549.7	905.0	0.0	0.0	0.0	30.0	0.0	44.0	0.0	0.0	0.0	3,641.5	590.6	0.0	0.0	5.0	0.0	0.0	19,002.3	0.0	28,960.9	650.5
SWMAAC	BGE	998.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.5	0.0	0.0	0.0	154.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,198.9	0.0
	PEPCO	301.0	0.0	55.3	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	215.1	1,346.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	1,927.9	1,229.0
	SWMAAC Total	1,299.5	0.0	55.3	4.0	0.0	0.0	0.0	0.0	45.5	0.0	0.0	0.0	370.1	1,346.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	3,126.9	1,229.0
WMAAC	MEC	625.2	75.0	13.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,023.1	157.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,901.4	2.5
	PE	897.8	85.0	585.5	0.0	3.6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	5,841.0	887.8	0.0	0.0	0.0	0.0	0.0	260.2	0.0	8,564.0	0.0
	PPL	540.2	106.6	0.0	0.0	0.0	0.0	700.0	0.0	100.0	0.0	0.0	0.0	2,423.6	677.2	0.0	0.0	0.0	0.0	0.0	416.9	90.0	5,054.5	333.9
	WMAAC Total	2,063.2	266.6	599.0	7.5	3.6	3.0	700.0	0.0	100.0	0.0	0.0	0.0	9,287.7	1,722.1	0.0	0.0	0.0	0.0	0.0	677.1	90.0	15,519.8	336.4
Non-MAAC	AEP	9,368.8	6,015.0	822.1	0.0	379.2	0.0	0.0	51.0	0.0	0.0	0.0	0.0	38,076.0	11,943.7	0.0	76.0	0.0	0.0	0.0	3,458.4	0.0	70,190.1	80.0
	APS	2,511.8	5,020.0	112.0	0.0	0.0	0.0	0.0	15.0	0.0	14.4	0.0	0.0	5,867.3	2,464.3	0.0	0.0	0.0	0.0	0.0	844.6	16.3	16,865.6	0.0
	ATSI	1,654.3	1,895.0	523.7	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,909.3	800.8	0.0	0.0	0.0	0.0	0.0	816.1	0.0	11,604.7	659.0
	COMED	4,423.4	3,712.6	1,421.2	0.0	0.0	5.0	0.0	12.1	0.0	0.0	0.0	0.0	11,800.6	2,285.8	199.0	0.0	0.0	0.0	0.0	9,373.1	0.0	33,232.8	1,234.1
	DAY	340.0	1,150.0	43.5	0.0	13.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,640.5	338.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,526.7	0.0
	DUKE	277.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	679.9	40.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	1,007.1	1,300.0
	DLCO	155.0	0.0	208.5	0.0	0.0	0.0	0.0	46.8	0.0	0.0	0.0	0.0	58.9	37.5	0.0	0.0	0.0	0.0	20.0	0.0	0.0	526.7	565.0
	DOM	11,889.5	99.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33,359.9	7,253.8	0.0	0.0	0.0	0.0	0.0	5,417.2	0.0	59,157.4	1,027.0
	EKPC	126.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,835.2	2,626.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,587.5	0.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	430.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	608.5	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	30,746.0	17,891.6	4,269.0	5.5	393.0	5.0	0.0	124.9	0.0	14.4	0.0	0.0	105,657.6	27,969.4	209.0	76.0	0.0	0.0	20.0	19,909.3	16.3	207,307.1	4,865.1
	Total	38,301.5	18,707.9	5,828.3	17.0	396.6	8.0	730.0	124.9	189.5	14.4	0.0	0.0	118,957.0	31,628.6	209.0	76.0	11.0	0.0	20.0	39,588.7	106.3	254,914.6	7,081.0

Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derated wind resources to 13 percent of nameplate capacity until there was operational data to support a different conclusion.[38] PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent. Using the average derate factors, based on the derating of 39,588.7 MW of wind resources to 6,413.4 MW, 118,957.0 MW of solar resources to 55,552.9 MW, 31,628.6 MW of solar + storage resources to 14,770.6 MW, 209.0 MW of solar + wind resources to 97.6 MW and 106.3 MW of wind + storage resources to 17.2 MW, the 254,914.6 MW currently under construction, suspended or active in the queue would be reduced to 141,276.7 MW.

Beginning with the 2023/2024 Delivery Year, unforced capacity for intermittent resources and limited duration resources will be determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis will determine capacity derates by resource class. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. The 2023/2024 ELCC class rating for wind resources is 15.0 percent, for solar resources with tracking panels is 54.0 percent and for solar resources with fixed panels is 38.0 percent.[39] The ELCC class rating for battery or energy storage resources replaces the 10 hour rule that was previously used to determine the unforced capacity value for an energy storage resource. PJM defined four different energy storage classes differentiated by duration. The ELCC class rating is 83.0 percent for storage resources that can continuously generate energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 98.0 percent for six hour storage and 100 percent for 8 hour storage and 10 hour storage.[40]

37 This data includes only projects with a status of active, under construction, or suspended.
38 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
39 *ELCC Class Ratings for 2023-2024 BRA*, PJM Interconnection L.L.C. (December 16, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>
40 Additional information available in *PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, PJM Interconnection L.L.C. (August 1, 2021).

Withdrawn Projects

The queue contains a substantial number of projects that are not likely to be built. The queue process results in a substantial number of projects that are withdrawn. Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage, but the actual calculation of commercial probability factors is less than transparent.[41] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rates are shown in Table 12-20 and Table 12-21.

Table 12-20 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 3,269 projects withdrawn as of December 31, 2021, 1,627 (49.8 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 3,269 projects withdrawn, 615 (18.8 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-20 Last milestone at time of withdrawal: January 1, 1997 through December 31, 2021

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	592	18.1%	77	868
Feasibility Study	1,035	31.7%	268	1,633
System Impact Study	724	22.1%	701	3,248
Facilities Study	303	9.3%	1,134	4,107
Construction Service Agreement (CSA) or beyond	615	18.8%	1,379	7,864
Total	3,269	100.0%		

Average Time in Queue

Table 12-21 shows the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,095 days, or 3.0 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 619 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-21 Project queue times by status (days): December 31, 2021[42]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	576	492	8	5,401
In-Service	1,095	799	0	5,306
Suspended	1,549	753	457	4,841
Under Construction	1,662	721	654	4,599
Withdrawn	619	741	0	7,864

Table 12-22 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 2,867 projects in the queue as of December 31, 2021, 199 (6.9 percent) had a completed feasibility study and 447 (15.6 percent) had a completed construction service agreement.

Table 12-22 Project queue times by milestone (days): December 31, 2021

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	1,271	44.3%	512	793
Feasibility Study	199	6.9%	529	1,208
System Impact Study	930	32.4%	853	2,284
Facilities Study	20	0.7%	1,506	2,983
Construction Service Agreement (CSA) or beyond	447	15.6%	1,379	5,401
Total	2,867	100.0%		

41 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
42 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Table 12-23 shows the time spent in the queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the queue to the time the project goes in service has generally been decreasing compared to the period prior to 2017 although there are significant exceptions. For example, for a battery project entering the queue in 2015, there was an average of 1,082 days from the time it entered the queue until it went in service, compared to only 293 days when entering the queue in 2018, but the time increased to 600 days in 2019.

Table 12-23 Average time in queue (days) by fuel type and year submitted (In Service Projects): December 31, 2021[43]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Battery	983	609	417	692	789	1,082	941	383	293	600	544	
CC	1,310	1,551	1,663	1,419	1,175	1,052	746	908	309	512		
CT - Natural Gas	1,131	804	953	1,021	734	901	1,192	657	688	320	319	
CT - Oil	717		259									
CT - Other	729	634	954	1,248	718	360						
Fuel Cell						827	643					
Hydro - Pumped Storage						1,402						
Hydro - Run of River			1,325	614	332		580	426	606			
Nuclear	885	866		1,234								
RICE - Natural Gas			1,702	1,053	1,332	798		250				
RICE - Oil						1,849						
RICE - Other	638	1,385	1,479	241	627	622	491		466			
Solar	1,701	1,313	969	1,014	1,003	1,489	1,211	997	855	488	295	
Solar + Storage									553			
Solar + Wind												
Steam - Coal	745		513	1,010	583	853	677	647				
Steam - Natural Gas				1,182		421	751					
Steam - Oil												
Steam - Other	256	838	643									
WInd	2,748	2,711	1,750	1,589	1,205	1,463	1,443	1,200	561			
Wind + Storage												

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed.

Table 12-24 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and any milestone completed beyond the FSA including a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA) and Wholesale Market Participant Agreement (WMPA) as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone.[44] For each unit type, the total MW in service was divided by the total energy MW entered in the queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all battery projects to ever enter the queue and complete the system impact study stage, 12.8 percent of the queued MW have gone into service. The completion rate for battery projects increases to 35.2 percent when battery projects complete the facility study agreement and further increases to 41.8 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 0.6 percent of the queued MW have gone into service.

43 A blank cell in this table means that no project of that fuel type, which was submitted to the queue in that year, subsequently went in service.

44 All milestones after the FSA are included in the totals under the CSA headings of the tables within Section 12, "Generation and Transmission Planning".

Table 12-24 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: December 31, 2021

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	12.8%	35.2%	41.8%	0.6%
CC	32.3%	49.6%	75.6%	14.5%
CT - Natural Gas	65.4%	80.5%	85.3%	41.6%
CT - Oil	35.4%	59.6%	90.8%	25.4%
CT - Other	12.3%	18.6%	29.5%	8.4%
Fuel Cell	30.6%	31.6%	31.6%	30.2%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	24.1%
Hydro - Run of River	42.8%	60.7%	68.1%	20.9%
Nuclear	35.2%	42.1%	51.3%	28.6%
RICE - Natural Gas	30.7%	42.8%	47.4%	25.9%
RICE - Oil	34.0%	59.7%	59.7%	26.2%
RICE - Other	89.0%	91.4%	92.0%	78.1%
Solar	18.0%	41.8%	51.3%	2.7%
Solar + Storage	0.0%	54.5%	54.5%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.6%	25.4%	37.5%	6.3%
Steam - Natural Gas	91.1%	91.1%	91.1%	90.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	30.4%	39.9%	47.8%	27.1%
Wind	18.9%	35.9%	51.7%	7.9%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On December 31, 2021, 254,914.6 MW were in generation request queues in the status of active, under construction or suspended. Of the total 254,914.6 MW in the queue, 151,857.1 MW (59.6 percent) have reached at least the SIS milestone and 103,057.5 MW (40.4 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or any milestone beyond the FSA, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 41,074.4 MW (16.1 percent) of new generation in the queue are expected to go into service.

Table 12-25 shows the percent of all project MW, by unit type, to go in service by year submitted to the queue. Of all battery projects that entered the queue in 2010, 65.5 percent reached the status of in service by December 31, 2021. Of all battery projects that entered the queue in 2016, only 1.3 percent have reached the status of in service as of December 31, 2021.

Table 12-25 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: December 31, 2021

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Battery	65.5%	8.3%	15.1%	43.9%	21.5%	7.7%	1.3%	4.1%	0.3%	0.0%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	5.6%	2.2%	6.1%	1.2%	0.5%	N/A	0.0%
CT - Natural Gas	100.0%	98.3%	89.7%	23.5%	32.0%	0.2%	8.2%	16.8%	4.3%	0.9%	0.4%	0.0%
CT - Oil	100.0%	N/A	1.2%	0.0%	0.0%	N/A	N/A	N/A	0.0%	0.0%	0.0%	N/A
CT - Other	28.8%	27.1%	36.1%	100.0%	0.0%	100.0%	N/A	0.0%	N/A	N/A	N/A	0.0%
Fuel Cell	N/A	N/A	N/A	N/A	N/A	67.4%	12.5%	0.0%	N/A	0.0%	N/A	0.0%
Hydro - Pumped Storage	N/A	N/A	N/A	N/A	N/A	100.0%	N/A	N/A	0.0%	0.0%	N/A	0.0%
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	N/A	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%
Nuclear	15.5%	1.6%	0.0%	100.0%	N/A	N/A	0.0%	71.6%	0.0%	N/A	0.0%	N/A
RICE - Natural Gas	N/A	N/A	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	N/A	N/A	N/A	0.0%
RICE - Oil	0.0%	0.0%	N/A	N/A	N/A	30.8%	N/A	N/A	N/A	N/A	N/A	N/A
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	N/A	N/A	N/A
Solar	10.7%	7.1%	16.9%	24.4%	30.7%	22.2%	10.1%	1.6%	0.5%	0.0%	0.0%	0.0%
Solar + Storage	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	0.0%	0.0%	N/A	N/A
Steam - Natural Gas	N/A	N/A	N/A	100.0%	0.0%	100.0%	100.0%	100.0%	N/A	N/A	0.0%	N/A
Steam - Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	0.0%
WInd	6.1%	3.4%	2.5%	5.8%	20.7%	12.5%	12.3%	2.6%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	N/A	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%	N/A	N/A	N/A	N/A
All	11.7%	18.9%	26.5%	32.7%	34.3%	9.0%	6.0%	3.1%	0.6%	0.0%	0.0%	0.0%

Queue Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-26 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, biomass, renewable hybrid and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 4,491 projects entered from January 2015 through December 2021, 3,344 projects (74.5 percent) were renewable. Of the 1,301 projects entered in 2021, 956 projects (73.5 percent) were renewable.

Table 12-26 Number of projects entered in the queue: December 31, 2021

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Total
1997	2	0	11	13
1998	0	0	18	18
1999	1	5	84	90
2000	2	3	78	83
2001	4	6	81	91
2002	3	15	33	51
2003	1	34	18	53
2004	4	17	33	54
2005	3	75	55	133
2006	9	67	81	157
2007	9	65	145	219
2008	3	102	111	216
2009	10	107	56	173
2010	5	370	66	441
2011	6	264	85	355
2012	2	59	98	159
2013	1	54	99	154
2014	0	100	92	192
2015	0	134	175	309
2016	2	298	99	399
2017	2	293	60	355
2018	1	343	96	440
2019	0	545	152	697
2020	2	775	213	990
2021	0	956	345	1,301
Total	72	4,687	2,384	7,143

As of December 31, 2021, renewable projects make up 76.0 percent of all projects in the queue and those projects account for 75.1 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2021 (Table 12-27).

Table 12-27 Queue details by fuel group: December 31, 2021

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	6	0.2%	189.5	0.1%
Renewable	2,178	76.0%	191,352.4	75.1%
Traditional	683	23.8%	63,372.7	24.9%
Total	2,867	100.0%	254,914.6	100.0%

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue.

While renewables currently make up the majority of both projects and nameplate MW in the queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables (Table 12-24). Table 12-28 shows the total MW of all projects in the queue as of December 31, 2021, in the status of active, suspended and under construction, by unit type. Table 12-28 also shows the total MW for each fuel type adjusted based on current historical completion rates and for the average solar and wind derates. Of the 18,707.9 MW of combined cycle projects in the queue, 11,128.3 MW (59.5 percent) are expected to go in service based on historical completion rates as of December 31, 2021. Of the 191,372.4 MW of renewable projects in the queue, only 24,300.6 MW (12.7 percent) are expected to go in service based on historical completion rates. Of the 191,372.4 MW of renewable projects in the queue, only 9,781.6 MW (5.1 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

Table 12-28 Queue totals for projects (active, suspended and under construction) by unit type adjusted based on current historical completion rates and average solar and wind derates (MW): December 31, 2021

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and Derate Adjusted MW in Queue
Battery	38,301.5	1,460.5	1,460.5
CC	18,707.9	11,128.3	11,128.3
CT - Natural Gas	5,828.3	4,025.0	4,025.0
CT - Oil	17.0	13.2	13.2
CT - Other	396.6	33.3	33.3
Fuel Cell	8.0	2.5	2.5
Hydro - Pumped Storage	730.0	707.2	707.2
Hydro - Run of River	124.9	56.8	56.8
Nuclear	189.5	73.8	73.8
RICE - Natural Gas	14.4	3.7	3.7
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	118,957.0	16,424.1	7,670.1
Solar + Storage	31,628.6	618.6	288.9
Solar + Wind	209.0	0.0	0.0
Steam - Coal	76.0	25.9	25.9
Steam - Natural Gas	11.0	10.0	10.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	20.0	5.4	5.4
Wind	39,588.7	6,485.9	1,050.7
Wind + Storage	106.3	0.0	0.0
Total	254,914.6	41,074.4	26,555.3

Queue Analysis by Unit Type and Project Classification

Table 12-29 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through December 31, 2021. As of December 31, 2021, 7,143 projects, representing 761,657.5 MW, have entered the queue process since its inception. Of those, 1,007 projects, representing 76,511.8 MW, went into service. Of the projects that entered the queue process, 3,269 projects, representing 430,231.1 MW (56.5 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

A total of 5,696 projects have been classified as new generation and 1,447 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 5,613 projects (78.6 percent) of all 7,143 generation queue projects to enter the queue since January 1, 1997.

Table 12-29 Status of all generation queue projects: January 1, 1997 through December 31, 2021

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	24	62	48	10	25	3	0	10	2	10	0	55	182	1	0	8	5	0	4	97	0	546
	Upgrade	7	108	111	15	5	0	3	19	42	9	2	16	38	0	0	55	10	0	8	13	0	461
Under Construction	New Generation	0	5	1	0	0	0	0	0	0	0	0	0	29	2	0	0	0	0	0	1	0	38
	Upgrade	0	7	16	8	0	1	0	0	1	0	0	0	11	1	0	1	0	0	0	0	0	46
Suspended	New Generation	4	7	2	0	0	0	0	0	0	0	0	0	37	5	0	0	0	0	0	2	1	58
	Upgrade	0	5	2	0	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	1	14
Withdrawn	New Generation	194	432	29	10	81	26	2	43	9	29	12	16	1,437	78	0	55	1	0	34	458	0	2,946
	Upgrade	50	98	15	13	13	2	0	5	13	0	2	3	61	1	0	15	0	0	2	30	0	323
Active	New Generation	327	6	5	0	6	0	2	6	0	1	0	0	1,365	290	2	0	1	0	1	96	0	2,108
	Upgrade	224	16	29	2	2	2	1	2	5	0	0	0	256	36	0	3	2	0	0	22	1	603
Total Projects	New Generation	549	512	85	20	112	29	4	59	11	40	12	71	3,050	376	2	63	7	0	39	654	1	5,696
	Upgrade	281	234	173	38	20	5	4	26	61	9	4	19	372	38	0	74	12	0	10	65	2	1,447

Table 12-30 shows the totals in Table 12-29 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 73.1 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 19.2 percent of hydro run of river upgrades were withdrawn and 7.7 percent of hydro run of river upgrades are active in the queue.

Table 12-30 Status of all generation queue projects as a percent of total projects by classification: January 1, 1997 through December 31, 2021

		Percent of Projects											
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other
In Service	New Generation	4.4%	12.1%	56.5%	50.0%	22.3%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%
	Upgrade	2.5%	46.2%	64.2%	39.5%	25.0%	0.0%	75.0%	73.1%	68.9%	100.0%	50.0%	84.2%
Under Construction	New Generation	0.0%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	3.0%	9.2%	21.1%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%
Suspended	New Generation	0.7%	1.4%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	2.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	35.3%	84.4%	34.1%	50.0%	72.3%	89.7%	50.0%	72.9%	81.8%	72.5%	100.0%	22.5%
	Upgrade	17.8%	41.9%	8.7%	34.2%	65.0%	40.0%	0.0%	19.2%	21.3%	0.0%	50.0%	15.8%
Active	New Generation	59.6%	1.2%	5.9%	0.0%	5.4%	0.0%	50.0%	10.2%	0.0%	2.5%	0.0%	0.0%
	Upgrade	79.7%	6.8%	16.8%	5.3%	10.0%	40.0%	25.0%	7.7%	8.2%	0.0%	0.0%	0.0%

Project Status	Project Classification	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	6.0%	0.3%	0.0%	12.7%	71.4%	0.0%	10.3%	14.8%	0.0%	9.6%
	Upgrade	10.2%	0.0%	0.0%	74.3%	83.3%	0.0%	80.0%	20.0%	0.0%	31.9%
Under Construction	New Generation	1.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.7%
	Upgrade	3.0%	2.6%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%
Suspended	New Generation	1.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	100.0%	1.0%
	Upgrade	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.0%
Withdrawn	New Generation	47.1%	20.7%	0.0%	87.3%	14.3%	0.0%	87.2%	70.0%	0.0%	51.7%
	Upgrade	16.4%	2.6%	0.0%	20.3%	0.0%	0.0%	20.0%	46.2%	0.0%	22.3%
Active	New Generation	44.8%	77.1%	100.0%	0.0%	14.3%	0.0%	2.6%	14.7%	0.0%	37.0%
	Upgrade	68.8%	94.7%	0.0%	4.1%	16.7%	0.0%	0.0%	33.8%	50.0%	41.7%

Table 12-31 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 458 new generation wind projects that have been withdrawn from the queue as of December 31, 2021, (as shown in Table 12-29) constitute 79,866.2 MW. The 432 new generation combined cycle projects that have been withdrawn in the same time period constitute 216,941.7 MW.

Table 12-31 Status of all generation (MW) in the generation queue: January 1, 1997 through December 31, 2021

		Percent of Projects											
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other
In Service	New Generation	4.4%	12.1%	56.5%	50.0%	22.3%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%
	Upgrade	2.5%	46.2%	64.2%	39.5%	25.0%	0.0%	75.0%	73.1%	68.9%	100.0%	50.0%	84.2%
Under Construction	New Generation	0.0%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	3.0%	9.2%	21.1%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%
Suspended	New Generation	0.7%	1.4%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	2.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	35.3%	84.4%	34.1%	50.0%	72.3%	89.7%	50.0%	72.9%	81.8%	72.5%	100.0%	22.5%
	Upgrade	17.8%	41.9%	8.7%	34.2%	65.0%	40.0%	0.0%	19.2%	21.3%	0.0%	50.0%	15.8%
Active	New Generation	59.6%	1.2%	5.9%	0.0%	5.4%	0.0%	50.0%	10.2%	0.0%	2.5%	0.0%	0.0%
	Upgrade	79.7%	6.8%	16.8%	5.3%	10.0%	40.0%	25.0%	7.7%	8.2%	0.0%	0.0%	0.0%

Project Status	Project Classification	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	6.0%	0.3%	0.0%	12.7%	71.4%	0.0%	10.3%	14.8%	0.0%	9.6%
	Upgrade	10.2%	0.0%	0.0%	74.3%	83.3%	0.0%	80.0%	20.0%	0.0%	31.9%
Under Construction	New Generation	1.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.7%
	Upgrade	3.0%	2.6%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%
Suspended	New Generation	1.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	100.0%	1.0%
	Upgrade	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.0%
Withdrawn	New Generation	47.1%	20.7%	0.0%	87.3%	14.3%	0.0%	87.2%	70.0%	0.0%	51.7%
	Upgrade	16.4%	2.6%	0.0%	20.3%	0.0%	0.0%	20.0%	46.2%	0.0%	22.3%
Active	New Generation	44.8%	77.1%	100.0%	0.0%	14.3%	0.0%	2.6%	14.7%	0.0%	37.0%
	Upgrade	68.8%	94.7%	0.0%	4.1%	16.7%	0.0%	0.0%	33.8%	50.0%	41.7%

Table 12-32 shows the MW totals in Table 12-31 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 63.4 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and December 31, 2021.

Table 12-32 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through December 31, 2021

		Percent of Projects											
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other
In Service	New Generation	4.4%	12.1%	56.5%	50.0%	22.3%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%
	Upgrade	2.5%	46.2%	64.2%	39.5%	25.0%	0.0%	75.0%	73.1%	68.9%	100.0%	50.0%	84.2%
Under Construction	New Generation	0.0%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	3.0%	9.2%	21.1%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%
Suspended	New Generation	0.7%	1.4%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	2.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	35.3%	84.4%	34.1%	50.0%	72.3%	89.7%	50.0%	72.9%	81.8%	72.5%	100.0%	22.5%
	Upgrade	17.8%	41.9%	8.7%	34.2%	65.0%	40.0%	0.0%	19.2%	21.3%	0.0%	50.0%	15.8%
Active	New Generation	59.6%	1.2%	5.9%	0.0%	5.4%	0.0%	50.0%	10.2%	0.0%	2.5%	0.0%	0.0%
	Upgrade	79.7%	6.8%	16.8%	5.3%	10.0%	40.0%	25.0%	7.7%	8.2%	0.0%	0.0%	0.0%

Project Status	Project Classification	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	6.0%	0.3%	0.0%	12.7%	71.4%	0.0%	10.3%	14.8%	0.0%	9.6%
	Upgrade	10.2%	0.0%	0.0%	74.3%	83.3%	0.0%	80.0%	20.0%	0.0%	31.9%
Under Construction	New Generation	1.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.7%
	Upgrade	3.0%	2.6%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%
Suspended	New Generation	1.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	100.0%	1.0%
	Upgrade	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.0%
Withdrawn	New Generation	47.1%	20.7%	0.0%	87.3%	14.3%	0.0%	87.2%	70.0%	0.0%	51.7%
	Upgrade	16.4%	2.6%	0.0%	20.3%	0.0%	0.0%	20.0%	46.2%	0.0%	22.3%
Active	New Generation	44.8%	77.1%	100.0%	0.0%	14.3%	0.0%	2.6%	14.7%	0.0%	37.0%
	Upgrade	68.8%	94.7%	0.0%	4.1%	16.7%	0.0%	0.0%	33.8%	50.0%	41.7%

Table 12-33 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 73.0 percent of all new projects entering the generation queue have been combined cycle (11.7 percent), wind (16.0 percent) or solar projects (45.3 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015 through December 31, 2021, 40,213.1 MW of renewable hybrid units have entered the queue.

Table 12-33 Queue project MW by unit type and queue entry year: January 1, 1997 through December 31, 2021

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,781.0
1999	0.0	29,412.7	2,061.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	32,412.2
2000	0.0	21,144.8	493.6	31.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	0.0	0.0	1,244.6	10.0	0.0	0.0	234.9	0.0	27,377.8
2002	0.0	4,154.0	11.7	0.0	70.5	0.0	0.0	293.0	236.0	8.0	23.3	4.5	0.0	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	0.0	0.0	1,187.0	0.0	0.0	0.0	1,614.7	0.0	8,488.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	0.0	0.0	6,360.0	0.0	0.0	24.0	6,020.0	0.0	20,364.9
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	0.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	0.0	29,964.2
2007	0.0	13,944.6	941.2	215.9	149.5	0.0	16.0	161.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	50.5	18,525.6	0.0	43,700.6
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	0.0	0.0	1,198.0	0.0	0.0	192.3	11,016.1	0.0	41,723.7
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	57.8	3,672.6	0.0	0.0	64.0	0.0	0.0	173.5	9,803.4	0.0	23,891.3
2011	24.1	19,744.0	29.5	0.0	174.6	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,014.0	0.0	0.0	357.0	0.0	0.0	49.0	5,576.4	0.0	28,269.9
2012	142.6	18,014.8	282.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	284.6	0.0	0.0	1,837.0	0.0	0.0	143.1	1,529.8	0.0	22,746.8
2013	217.4	10,493.1	1,201.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	0.0	0.0	158.0	40.0	0.0	44.7	1,407.9	0.0	14,063.4
2014	246.9	11,704.5	1,532.5	401.0	7.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,590.0	0.0	0.0	1,730.5	27.0	0.0	43.1	1,689.7	0.0	19,099.0
2015	546.9	27,540.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,920.7	2.0	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,550.9
2016	111.1	18,802.5	1,392.0	0.0	0.0	3.4	0.0	12.5	50.3	23.5	0.0	38.9	11,605.5	85.6	0.0	80.0	77.0	0.0	0.0	3,448.7	16.3	35,747.2
2017	24.6	5,477.6	691.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,652.9	424.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,726.4
2018	1,513.7	11,080.1	2,647.4	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,734.0	4,573.9	0.0	49.0	0.0	0.0	0.0	17,710.4	0.0	58,053.7
2019	5,688.3	3,332.5	1,572.1	13.0	0.0	3.0	500.0	99.0	0.0	0.0	0.0	0.0	27,422.0	9,596.1	0.0	11.0	0.0	0.0	0.0	11,585.4	0.0	59,822.3
2020	11,163.9	0.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	37,421.7	10,391.9	199.0	0.0	11.0	0.0	0.0	6,915.9	0.0	67,134.1
2021	25,637.3	2,129.0	771.0	0.0	396.6	5.0	30.0	23.5	0.0	14.4	0.0	0.0	48,644.3	14,823.5	10.0	0.0	0.0	0.0	20.0	11,160.0	0.0	103,664.6
Total	45,544.3	290,259.5	19,946.4	3,145.3	1,876.9	16.3	1,620.0	3,043.4	13,266.3	669.3	104.2	589.4	169,900.2	39,897.8	209.0	36,781.1	986.5	0.0	1,836.7	131,858.6	106.3	761,657.5

Combined Cycle Project Analysis

Table 12-34 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 46 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 12 projects (26.1 percent) are located in the AEP Zone.

Table 12-34 Status of all combined cycle queue projects by zone (number of projects): January 1, 1997 through December 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	4	3	4	2	1	0	2	0	7	2	0	7	4	0	5	2	4	8	6	0	62
	Upgrade	3	12	9	5	0	5	0	0	0	16	5	0	6	3	0	13	4	4	9	14	0	108
Under Construction	New Generation	0	3	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	4	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	7
Suspended	New Generation	0	1	2	2	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
	Upgrade	0	1	1	0	0	0	0	0	0	0	0	0	1	0	0	0	2	0	0	0	0	5
Withdrawn	New Generation	23	19	45	13	8	14	0	1	2	19	16	3	26	25	0	43	41	34	42	56	2	432
	Upgrade	7	7	9	4	0	4	0	1	0	11	5	0	7	7	0	3	5	5	8	15	0	98
Active	New Generation	0	2	2	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	Upgrade	1	1	4	0	0	2	0	0	0	3	1	0	0	0	0	1	0	1	2	0	0	16
Total Projects	New Generation	24	29	52	19	10	20	1	3	2	26	18	3	33	29	0	48	43	38	50	62	2	512
	Upgrade	11	25	23	9	0	11	0	1	0	30	11	0	14	11	0	17	11	10	20	30	0	234

Table 12-35 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 18,707.9 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 6,015.0 MW (32.2 percent) are located in the AEP Zone.

Table 12-35 Status of all combined cycle queue projects by zone (MW): January 1, 1997 through December 31, 2021

		Project MW										
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL
In Service	New Generation	650.0	3,032.0	1,970.0	3,751.0	140.0	600.0	0.0	533.0	0.0	5,828.6	319.2
	Upgrade	229.0	384.0	939.7	344.0	0.0	633.6	0.0	0.0	0.0	978.0	102.0
Under Construction	New Generation	0.0	2,579.0	0.0	0.0	0.0	2,350.9	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	916.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	1,050.0	1,091.0	1,895.0	0.0	100.0	1,150.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	35.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	8,542.4	12,509.5	21,832.1	8,641.0	3,122.1	10,142.0	0.0	134.5	665.0	13,921.0	5,145.4
	Upgrade	149.4	711.0	874.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	959.0
Active	New Generation	0.0	1,150.0	3,370.0	0.0	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	7.6	285.0	514.0	0.0	0.0	111.7	0.0	0.0	0.0	99.0	451.0
Total Projects	New Generation	9,192.4	20,320.5	28,263.1	14,287.0	3,262.1	14,342.9	1,150.0	667.5	665.0	19,749.6	5,464.6
	Upgrade	386.0	2,331.0	2,372.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,857.4	1,512.0

Project Status	Project Classification	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,142.0	2,448.5	0.0	34,762.0
	Upgrade	0.0	110.0	83.9	0.0	1,075.5	142.3	228.6	1,320.0	845.9	0.0	7,416.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,929.9
	Upgrade	0.0	0.0	75.0	0.0	0.0	0.0	0.0	51.6	51.1	0.0	1,093.7
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,286.0
	Upgrade	0.0	35.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	200.0
Withdrawn	New Generation	991.8	13,562.6	13,001.0	0.0	23,340.0	16,114.0	21,308.2	18,917.7	25,044.6	6.9	216,941.7
	Upgrade	0.0	378.0	1,742.0	0.0	240.0	1,040.6	229.1	703.0	2,217.9	0.0	12,431.4
Active	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,670.0
	Upgrade	0.0	0.0	0.0	0.0	5.0	0.0	0.0	55.0	0.0	0.0	1,528.3
Total Projects	New Generation	991.8	15,228.4	15,558.0	0.0	26,005.0	18,014.0	22,868.2	24,059.7	27,493.1	6.9	267,589.6
	Upgrade	0.0	523.0	1,900.9	0.0	1,320.5	1,267.9	457.7	2,129.6	3,114.9	0.0	22,669.9

Combustion Turbine – Natural Gas Project Analysis

Table 12-36 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 55 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 14 projects (25.5 percent) are located in the COMED Zone.

Table 12-36 Status of all combustion turbine – natural gas generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	5	0	6	0	3	0	0	0	1	3	6	0	2	1	0	2	4	2	4	9	0	48
	Upgrade	4	10	8	2	0	12	5	0	0	28	8	0	4	1	0	4	4	3	4	14	0	111
Under Construction	New Generation	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	1	2	0	4	0	0	0	0	0	0	1	4	0	0	4	0	0	0	0	16
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0	2
	Upgrade	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	1	6	0	0	2	1	1	0	0	4	0	1	1	0	0	1	5	0	1	5	0	29
	Upgrade	2	1	1	1	0	2	2	0	1	3	0	0	0	1	0	0	1	0	0	0	0	15
Active	New Generation	1	1	0	0	0	0	0	0	0	2	0	0	0	0	0	0	1	0	0	0	0	5
	Upgrade	2	2	1	5	0	9	2	0	1	1	0	0	0	0	0	0	1	5	0	0	0	29
Total Projects	New Generation	7	7	6	0	5	1	1	0	2	9	6	1	3	1	0	3	11	2	5	15	0	85
	Upgrade	8	13	12	10	0	28	9	0	2	32	8	0	5	6	0	4	10	8	4	14	0	173

Table 12-37 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 5,828.3 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,421.2 MW (24.4 percent) are located in the COMED Zone.

Table 12-37 Status of all combustion turbine – natural gas queue projects by zone (MW): January 1, 1997 through December 31, 2021

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	360.7	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	14.4	1,081.0	1,140.0	0.0	520.0	10.0	0.0	559.0	361.9	5.0	150.9	925.9	0.0	6,327.8
	Upgrade	43.7	227.0	187.7	40.0	0.0	371.0	60.0	0.0	0.0	925.7	86.0	0.0	200.0	34.1	0.0	42.0	28.0	32.0	252.3	215.0	0.0	2,744.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0
	Upgrade	0.0	0.0	12.0	5.0	0.0	87.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.5	0.0	0.0	12.5	0.0	0.0	0.0	0.0	130.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	463.0	0.0	0.0	675.0	0.0	1,138.0
	Upgrade	0.0	0.0	30.0	0.0	0.0	350.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	380.0
Withdrawn	New Generation	7.5	1,519.0	0.0	0.0	153.6	10.0	104.0	0.0	0.0	1,069.8	0.0	73.0	2.1	0.0	0.0	0.5	326.8	0.0	19.9	1,140.1	0.0	4,426.3
	Upgrade	165.5	6.0	4.0	25.0	0.0	23.0	104.0	0.0	0.0	57.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	0.0	0.0	0.0	0.0	619.5
Active	New Generation	230.0	700.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	2,086.0
	Upgrade	0.0	122.1	70.0	518.7	0.0	984.2	43.5	0.0	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.0	55.3	0.0	0.0	0.0	1,889.3
Total Projects	New Generation	598.2	2,219.0	1,176.0	0.0	176.6	10.0	104.0	0.0	219.4	3,288.8	1,140.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	14,183.1
	Upgrade	209.2	355.1	303.7	588.7	0.0	1,815.2	207.5	0.0	3.5	982.7	86.0	0.0	200.0	47.6	0.0	42.0	367.5	87.3	252.3	215.0	0.0	5,763.3

Wind Project Analysis

Table 12-38 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 121 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 46 projects (38.0 percent) are located in the COMED Zone.

Table 12-38 Status of all wind generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	19	17	0	0	26	0	0	0	3	0	0	0	0	0	0	23	0	8	0	0	97
	Upgrade	0	0	3	0	0	5	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	13
Under Construction	New Generation	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0	0	2
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	18	115	46	8	0	108	15	0	0	21	11	1	3	0	0	0	64	0	47	1	0	458
	Upgrade	2	2	7	0	0	8	0	0	0	3	0	0	0	0	0	0	6	0	2	0	0	30
Active	New Generation	6	18	5	3	0	36	0	0	0	7	11	0	5	0	0	0	2	0	2	1	0	96
	Upgrade	0	1	1	0	0	10	0	0	0	0	5	0	4	0	0	0	1	0	0	0	0	22
Total Projects	New Generation	25	152	69	11	0	170	15	0	0	32	22	1	8	0	0	0	89	0	58	2	0	654
	Upgrade	2	3	11	0	0	23	0	0	0	3	5	0	4	0	0	0	12	0	2	0	0	65

Table 12-39 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 39,588.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 9,373.1 MW (23.7 percent) are located in the COMED Zone.

Table 12-39 Status of all wind generation queue projects by zone (MW): January 1, 1997 through December 31, 2021

		Project MW										
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL
In Service	New Generation	7.5	3,544.6	1,314.6	0.0	0.0	4,088.9	0.0	0.0	0.0	322.5	0.0
	Upgrade	0.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	0.0	110.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.3	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	4,643.6	23,638.0	3,552.2	1,295.6	0.0	25,327.3	2,128.0	0.0	0.0	4,988.4	2,968.8
	Upgrade	5.0	370.0	119.4	0.0	0.0	755.7	0.0	0.0	0.0	114.0	0.0
Active	New Generation	3,441.6	3,441.7	527.0	816.1	0.0	8,887.3	0.0	0.0	0.0	5,116.9	6,686.2
	Upgrade	0.0	16.6	207.6	0.0	0.0	485.8	0.0	0.0	0.0	0.0	985.3
Total Projects	New Generation	8,092.7	30,624.3	5,503.8	2,111.7	0.0	38,303.5	2,128.0	0.0	0.0	10,728.1	9,655.0
	Upgrade	5.0	386.6	332.0	0.0	0.0	1,454.7	0.0	0.0	0.0	114.0	985.3

Project Status	Project Classification	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	0.0	0.0	0.0	0.0	1,047.0	0.0	226.5	0.0	0.0	10,551.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	20.5	0.0	0.0	0.0	0.0	238.7
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	67.3	0.0	0.0	367.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	150.3	2,304.0	0.0	0.0	0.0	5,377.0	0.0	3,473.1	20.0	0.0	79,866.2
	Upgrade	0.0	0.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	1,613.4
Active	New Generation	0.0	4,259.2	0.0	0.0	0.0	159.9	0.0	349.6	1,300.0	0.0	34,985.5
	Upgrade	0.0	2,330.0	0.0	0.0	0.0	100.3	0.0	0.0	0.0	0.0	4,125.7
Total Projects	New Generation	150.3	6,563.2	0.0	0.0	0.0	6,583.9	0.0	4,116.5	1,320.0	0.0	125,880.8
	Upgrade	0.0	2,330.0	0.0	0.0	0.0	364.2	0.0	6.0	0.0	0.0	5,977.8

Solar Project Analysis

Table 12-40 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 1,704 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 402 projects (23.6 percent) are located in the DOM Zone.

Table 12-40 Status of all solar generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2021

		Number of Projects																				
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	9	7	8	0	1	1	1	1	0	41	11	0	53	0	0	1	1	1	2	44	0	182
	Upgrade	1	2	3	0	0	0	0	2	0	7	9	0	10	0	0	0	1	0	3	0	0	38
Under Construction	New Generation	1	3	3	0	0	0	1	0	0	12	6	0	0	0	0	0	0	0	0	3	0	29
	Upgrade	0	1	0	0	0	0	0	0	0	5	1	0	0	0	0	0	0	0	0	4	0	11
Suspended	New Generation	0	0	13	2	0	0	0	0	0	11	1	1	0	5	0	0	4	0	0	0	0	37
	Upgrade	0	0	1	0	0	0	0	1	0	0	0	0	2	2	0	0	0	0	0	0	0	6
Withdrawn	New Generation	186	133	98	33	15	45	24	16	2	242	150	16	195	24	1	9	78	23	54	93	0	1,437
	Upgrade	3	4	3	4	0	6	1	0	0	18	1	0	9	1	0	0	5	3	0	3	0	61
Active	New Generation	25	268	116	73	5	67	33	10	4	320	52	61	32	41	2	7	150	11	82	6	0	1,365
	Upgrade	3	68	18	22	0	15	11	1	1	54	8	5	2	8	2	0	18	0	20	0	0	256
Total Projects	New Generation	221	411	238	108	21	113	59	27	6	626	220	78	280	70	3	17	233	35	138	146	0	3,050
	Upgrade	7	75	25	26	0	21	12	4	1	84	19	5	23	11	2	0	24	3	23	7	0	372

Table 12-41 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 118,957.0 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 38,076.0 MW (32.0 percent) are located in the AEP Zone.

Table 12-41 Status of all solar generation queue projects by zone (MW): January 1, 1997 through December 31, 2021

		Project MW										
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL
In Service	New Generation	62.0	114.7	112.3	0.0	1.1	9.0	2.5	125.0	0.0	1,938.6	130.4
	Upgrade	0.0	150.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	45.1	0.0
Under Construction	New Generation	2.6	300.0	38.2	0.0	0.0	0.0	400.0	0.0	0.0	1,353.6	249.6
	Upgrade	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.0	0.0
Suspended	New Generation	0.0	0.0	192.5	70.0	0.0	0.0	0.0	0.0	0.0	729.9	202.0
	Upgrade	0.0	0.0	15.9	0.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0
Withdrawn	New Generation	2,097.0	8,990.4	2,623.7	1,725.5	121.6	3,386.2	1,923.9	689.4	33.0	13,430.2	2,590.9
	Upgrade	170.0	126.0	27.9	178.0	0.0	110.0	20.0	0.0	0.0	1,008.8	0.0
Active	New Generation	628.0	33,723.9	5,132.1	4,922.6	154.9	10,197.6	3,015.0	649.9	50.6	29,240.0	1,796.3
	Upgrade	48.0	4,032.1	488.6	916.7	0.0	1,603.0	225.5	20.0	8.3	1,995.4	72.0
Total Projects	New Generation	2,789.6	43,129.0	8,098.7	6,718.1	277.6	13,592.8	5,341.4	1,464.3	83.6	46,692.3	4,969.2
	Upgrade	218.0	4,328.1	532.4	1,094.7	0.0	1,713.0	245.5	105.0	8.3	3,090.3	72.0

Project Status	Project Classification	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	397.9	0.0	0.0	3.3	13.5	2.5	15.0	231.9	0.0	3,159.6
	Upgrade	0.0	14.3	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	294.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0	2,361.5
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	64.8
Suspended	New Generation	95.0	0.0	47.0	0.0	0.0	60.2	0.0	0.0	0.0	0.0	1,396.5
	Upgrade	0.0	18.6	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	84.5
Withdrawn	New Generation	998.9	1,617.4	819.7	78.0	78.4	2,565.1	438.0	1,002.1	565.6	0.0	45,774.8
	Upgrade	0.0	23.8	15.0	0.0	0.0	30.0	3.6	0.0	1.3	0.0	1,714.4
Active	New Generation	5,512.2	444.9	783.1	340.0	108.3	5,316.5	215.1	2,111.5	41.1	0.0	104,383.9
	Upgrade	228.0	8.8	153.0	90.0	0.0	464.3	0.0	312.1	0.0	0.0	10,665.8
Total Projects	New Generation	6,606.1	2,460.2	1,649.8	418.0	190.0	7,955.2	655.7	3,128.6	856.1	0.0	157,076.3
	Upgrade	228.0	65.5	208.0	90.0	0.0	494.3	3.6	322.1	5.1	0.0	12,823.9

Renewable Hybrid Project Analysis

Table 12-42 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone.[45] Of the 339 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 75 projects (22.1 percent) are located in the AEP Zone.

Table 12-42 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	2
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	1	0	0	0	0	0	0	0	0	0	0	3	0	0	1	0	1	0	0	6
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	4	10	5	5	0	5	0	0	0	26	0	8	0	1	0	0	4	1	1	8	0	78
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1
Active	New Generation	3	67	28	11	0	14	7	2	2	66	3	25	5	7	1	1	15	2	32	1	0	292
	Upgrade	1	7	2	2	0	2	3	0	0	6	0	3	0	1	0	0	3	0	7	0	0	37
Total Projects	New Generation	7	77	34	16	0	19	7	2	2	92	3	33	5	11	1	1	20	3	34	12	0	379
	Upgrade	1	8	3	2	0	2	3	0	0	6	0	3	0	2	0	0	3	0	7	0	0	40

45 PJM does not currently have a definition of a hybrid resource.

Table 12-43 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 31,943.9 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 11,943.7 MW (37.4 percent) are located in the AEP Zone.

Table 12-43 Status of all renewable hybrid generation queue projects by zone (MW): January 1, 1997 through December 31, 2021

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	1.1
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	0.0	2.6
	Upgrade	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Suspended	New Generation	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.0	0.0	0.0	3.0	0.0	90.0	0.0	0.0	218.0
	Upgrade	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3
Withdrawn	New Generation	14.5	3,360.8	375.0	334.9	0.0	629.9	0.0	0.0	0.0	2,114.9	0.0	1,004.0	0.0	20.0	0.0	0.0	180.5	20.0	180.0	29.9	0.0	8,264.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Active	New Generation	153.0	11,320.5	2,444.3	770.8	0.0	2,464.8	298.9	50.0	37.5	7,099.8	170.0	2,491.3	180.0	52.1	178.5	5.0	846.6	1,346.5	451.0	20.0	0.0	30,380.5
	Upgrade	60.0	620.0	0.0	30.0	0.0	20.0	40.0	0.0	0.0	154.0	0.0	135.0	0.0	0.0	0.0	0.0	38.2	0.0	226.2	0.0	0.0	1,323.4
Total Projects	New Generation	167.5	14,681.3	2,839.3	1,105.7	0.0	3,094.7	298.9	50.0	37.5	9,214.7	170.0	3,495.3	180.0	177.1	178.5	5.0	1,030.2	1,366.5	721.0	53.5	0.0	38,866.5
	Upgrade	60.0	623.2	16.3	30.0	0.0	20.0	40.0	0.0	0.0	154.0	0.0	135.0	0.0	3.7	0.0	0.0	38.2	0.0	226.2	0.0	0.0	1,346.6

Relationship Between Project Developer and Transmission Owner

A transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[46] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation or transmission of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a nonincumbent transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-44 shows the relationship between the project developer and transmission owner for all project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2021, by transmission owner and unit type. A project where the developer is affiliated with the transmission owner is classified as related. A project where the developer is not affiliated with the transmission owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in the DUKE Zone were projects developed by Duke Energy or subsidiaries of Duke Energy, the transmission owner for the DUKE Zone. These project MW are classified as related. There have been 667.5 MW of combined cycle projects that have entered the PJM generation queue in the DUKE Zone by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

Of the 761,657.5 MW that have entered the queue during the time period of January 1, 1997, through December 31, 2021, 71,432.6 MW (9.4 percent) have been submitted by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building in their own service territory. Of the 39,443.9 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2021, 14,287.3 MW (36.2 percent) were submitted by PSEG or one of their affiliated companies.

46 See OATT § 1 (Transmission Owner).

Table 12-44 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: December 31, 2021

				MW by Unit Type											
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other
AEP	AEP	Related	51	16.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0
		Unrelated	1026	10,879.0	21,973.5	2,574.1	7.5	506.5	0.0	0.0	453.6	0.0	12.0	0.0	75.4
AES	DAY	Related	13	20.0	0.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	116	654.9	1,150.0	273.5	0.0	15.7	0.0	0.0	0.0	0.0	0.0	0.0	10.0
DUQ	DUQ	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	42	175.0	665.0	222.9	40.0	19.2	0.0	0.0	194.6	1,879.0	0.0	0.0	0.0
DOM	DOM	Related	182	826.7	12,338.5	2,045.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0
		Unrelated	1051	11,891.0	9,268.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4
DUKE	DUKE	Related	12	37.3	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	42	355.4	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8
EKPC	EKPC	Related	2	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	130	146.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Exelon	ACEC	Related	5	0.0	730.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	370	1,339.0	8,848.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3
	BGE	Related	15	22.5	250.0	10.0	0.0	0.0	0.0	0.0	0.0	108.5	0.0	0.0	8.5
		Unrelated	73	1,236.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0
	COMED	Related	17	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	0.0	0.0
		Unrelated	530	5,614.1	16,823.2	1,529.2	42.0	65.2	5.0	0.0	22.7	0.0	35.0	0.0	67.7
	DPL	Related	8	1.0	1,365.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	383	1,022.5	5,611.6	1,226.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6
	PECO	Related	33	40.0	6,965.0	5.0	89.5	0.0	0.0	0.0	265.0	437.8	0.0	0.0	0.0
		Unrelated	92	25.3	20,360.5	596.5	2.0	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7
	PEPCO	Related	1	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	116	320.0	23,325.9	92.3	34.0	9.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5
First Energy	APS	Related	7	0.0	1,453.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	591	2,907.7	29,182.8	1,479.7	0.0	84.4	0.0	0.0	638.3	0.0	154.4	53.8	25.4
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0
		Unrelated	236	1,860.4	13,589.0	588.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9
	JCPLC	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0
		Unrelated	456	1,606.0	15,751.4	722.1	0.0	4.8	0.6	30.0	1.6	0.0	0.6	0.0	12.8
	MEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	190	869.9	17,458.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2
	PE	Related	4	0.0	534.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	542	1,327.2	18,747.9	1,532.2	0.0	218.0	3.0	16.0	46.3	0.0	341.8	8.0	14.8
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	22	0.0	2,261.0	0.0	0.0	0.0	0.0	0.0	109.0	1,600.0	0.0	0.0	0.0
		Unrelated	416	870.0	23,928.3	423.1	8.0	234.5	0.0	1,200.0	142.6	488.0	19.9	2.4	44.7
PSEG	PSEG	Related	109	0.0	11,836.1	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0
		Unrelated	244	1,479.5	18,771.9	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7
Con Ed	REC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2	0.0	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	489	964.5	40,946.4	4,217.8	189.5	0.0	0.0	374.0	396.4	5,886.3	0.0	0.0	68.5
		Unrelated	6654	44,579.8	249,313.1	15,728.6	2,955.8	1,876.9	16.3	1,246.0	2,647.0	7,380.0	669.3	104.2	520.9

Table 12-44 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: December 31, 2021 (continued)

Parent Company	Transmission Owner	Related to Developer	Number of Projects	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
AEP	AEP	Related	51	299.7	180.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,432.1
		Unrelated	1026	47,157.4	15,124.5	0.0	10,399.0	0.0	0.0	452.0	31,010.9	0.0	140,625.3
AES	DAY	Related	13	21.5	0.0	0.0	1,347.5	0.0	0.0	0.0	0.0	0.0	1,427.0
		Unrelated	116	5,565.4	338.9	0.0	0.0	0.0	0.0	0.0	2,128.0	0.0	10,136.4
DUQ	DUQ	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	42	91.9	37.5	0.0	2,810.0	0.0	0.0	20.0	0.0	0.0	6,155.1
DOM	DOM	Related	182	5,059.3	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	25,822.2
		Unrelated	1051	44,723.4	9,351.7	0.0	20.0	0.0	0.0	316.3	8,056.1	0.0	86,245.0
DUKE	DUKE	Related	12	106.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	179.7
		Unrelated	42	1,462.9	40.0	10.0	120.0	0.0	0.0	0.0	0.0	0.0	2,772.6
EKPC	EKPC	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8
		Unrelated	130	6,834.1	3,630.3	0.0	0.0	0.0	0.0	0.0	150.3	0.0	11,003.9
Exelon	ACEC	Related	5	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	738.3
		Unrelated	370	2,999.3	227.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	22,778.6
	BGE	Related	15	20.0	0.0	0.0	10.0	101.0	0.0	0.0	0.0	0.0	530.5
		Unrelated	73	257.6	0.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	8,133.1
	COMED	Related	17	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,490.0
		Unrelated	530	15,296.8	2,915.7	199.0	1,926.0	91.0	0.0	90.0	39,758.1	0.0	84,480.8
	DPL	Related	8	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,373.4
		Unrelated	383	5,033.8	170.0	0.0	653.0	15.0	0.0	65.0	10,640.3	0.0	25,165.3
	PECO	Related	33	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	7,809.3
		Unrelated	92	190.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,215.0
	PEPCO	Related	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
		Unrelated	116	659.3	1,366.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	27,488.5
First Energy	APS	Related	7	26.4	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	3,189.4
		Unrelated	591	8,604.7	2,839.3	0.0	4,092.0	0.0	0.0	184.4	5,835.8	16.3	56,098.9
	ATSI	Related	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0
		Unrelated	236	7,812.8	1,135.7	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	27,358.3
	JCPLC	Related	2	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0
		Unrelated	456	2,513.7	180.0	0.0	0.0	0.0	0.0	30.0	8,893.2	0.0	29,746.7
	MEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	190	1,857.8	180.8	0.0	0.0	0.0	0.0	84.0	0.0	0.0	21,889.7
	PE	Related	4	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	0.0	2,399.0
		Unrelated	542	8,449.6	1,068.4	0.0	561.0	590.0	0.0	525.0	6,948.1	0.0	40,397.0
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	6	508.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	686.5
PPL	PPL	Related	22	124.8	0.0	0.0	111.0	0.0	0.0	0.0	0.0	0.0	4,205.8
		Unrelated	416	3,325.9	857.2	0.0	6,896.6	0.0	0.0	31.0	4,122.5	90.0	42,684.8
PSEG	PSEG	Related	109	180.4	3.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	14,287.3
		Unrelated	244	680.8	49.9	0.0	0.0	25.0	0.0	0.0	1,320.0	0.0	25,156.7
Con Ed	REC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9
Total		Related	489	5,875.1	200.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	71,432.6
		Unrelated	6654	164,025.1	39,697.1	209.0	27,492.6	751.5	0.0	1,832.7	129,072.6	106.3	690,224.9

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-45 shows the relationship between the project developer and transmission owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2021, by transmission owner and project status. Of the 48,202.1 combined cycle project MW that have achieved in service or under construction status during this time period, 9,294.6 MW (19.3 percent) have been developed by transmission owners building in their own service territory. EKPC is the transmission owner with the highest percentage of affiliates building combined cycle projects in their own service territory. Of the 991.8 MW that entered the queue in the EKPC Zone during the time period of January 1, 1997, through December 31, 2021, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-45 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: December 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	678.0	0.0	0.0	0.0	678.0
		Unrelated	1,435.0	2,738.0	3,495.0	1,085.0	13,220.5	21,973.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	1,150.0	0.0	1,150.0
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	665.0	665.0
DOM	DOM	Related	75.0	4,762.5	0.0	0.0	7,501.0	12,338.5
		Unrelated	24.0	2,044.1	0.0	0.0	7,200.4	9,268.5
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	36.0	36.0
		Unrelated	0.0	533.0	0.0	0.0	134.5	667.5
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	821.8	821.8
		Unrelated	0.0	0.0	0.0	0.0	170.0	170.0
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	730.0	730.0
		Unrelated	7.6	879.0	0.0	0.0	7,961.8	8,848.4
	BGE	Related	0.0	130.0	0.0	0.0	120.0	250.0
		Unrelated	0.0	10.0	0.0	0.0	3,002.1	3,012.1
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,261.7	1,233.6	2,350.9	100.0	11,877.0	16,823.2
	DPL	Related	0.0	60.0	0.0	0.0	1,305.0	1,365.0
		Unrelated	451.0	361.2	0.0	0.0	4,799.4	5,611.6
	PECO	Related	0.0	0.0	0.0	0.0	6,965.0	6,965.0
		Unrelated	5.0	3,740.5	0.0	0.0	16,615.0	20,360.5
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,788.6	0.0	0.0	21,537.3	23,325.9
First Energy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0
		Unrelated	3,884.0	2,384.7	0.0	1,136.0	21,778.1	29,182.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	0.0	4,095.0	0.0	1,895.0	7,599.0	13,589.0
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,775.8	0.0	35.0	13,940.6	15,751.4
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	2,640.9	75.0	0.0	14,743.0	17,458.9
	PE	Related	0.0	0.0	0.0	0.0	534.0	534.0
		Unrelated	0.0	2,042.3	0.0	85.0	16,620.6	18,747.9
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	0.0	600.0	0.0	0.0	1,661.0	2,261.0
		Unrelated	55.0	5,862.0	51.6	0.0	17,959.7	23,928.3
PSEG	PSEG	Related	0.0	2,488.0	51.1	0.0	9,297.0	11,836.1
		Unrelated	0.0	806.4	0.0	0.0	17,965.5	18,771.9
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	6.9	6.9
Total		Related	75.0	9,243.5	51.1	0.0	31,576.8	40,946.4
		Unrelated	7,123.3	32,935.0	5,972.5	5,486.0	197,796.2	249,313.1

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-46 shows the relationship between the project developer and transmission owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2021, by transmission owner and project status. Of the 9,407.3 CT – natural gas project MW that have achieved in service or under construction status during this time period, 1,794.0 (19.1 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,956.0 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2021, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-46 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: December 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	822.1	227.0	0.0	0.0	1,525.0	2,574.1
AES	DAY	Related	0.0	38.0	0.0	0.0	0.0	38.0
		Unrelated	43.5	22.0	0.0	0.0	208.0	273.5
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3.5	14.4	205.0	0.0	0.0	222.9
DOM	DOM	Related	1,138.0	824.0	0.0	0.0	83.7	2,045.7
		Unrelated	0.0	1,182.7	0.0	0.0	1,043.1	2,225.8
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	73.0	73.0
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	230.0	404.4	0.0	0.0	173.0	807.4
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0
		Unrelated	0.0	13.0	0.0	0.0	153.6	166.6
	COMED	Related	296.0	0.0	0.0	0.0	0.0	296.0
		Unrelated	688.2	371.0	87.0	350.0	33.0	1,529.2
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,226.0	0.0	0.0	0.0	1,226.0
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	0.0	596.0	0.0	0.0	0.5	596.5
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	55.3	37.0	0.0	0.0	0.0	92.3
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	70.0	1,363.7	12.0	30.0	4.0	1,479.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	518.7	40.0	5.0	0.0	25.0	588.7
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	720.0	0.0	0.0	2.1	722.1
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	44.1	13.5	0.0	0.0	57.6
	PE	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	110.0	384.9	12.5	463.0	561.8	1,532.2
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	403.2	0.0	0.0	19.9	423.1
PSEG	PSEG	Related	0.0	912.0	0.0	0.0	906.1	1,818.1
		Unrelated	0.0	228.9	0.0	675.0	234.0	1,137.9
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	1,434.0	1,794.0	0.0	0.0	989.8	4,217.8
		Unrelated	2,541.3	7,278.3	335.0	1,518.0	4,056.0	15,728.6

Wind Project Developer and Transmission Owner Relationships

Table 12-47 shows the relationship between the project developer and transmission owner for all wind project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2021, by transmission owner and project status. Of the 10,900.3 wind project MW that have achieved in service or under construction status during this time period, 12.0 MW (0.1 percent) have been developed by transmission owners building in their own service territory. Dominion is the transmission owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 10,842.1 MW that entered the queue in the DOM Zone during the time period of January 1, 1997, through December 31, 2021, 2,786.0 MW (25.7 percent) have been submitted by Dominion or one of their affiliated companies.

Table 12-47 Relationship between project developer and transmission owner for all wind project MW in the queue: December 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,458.4	3,544.6	0.0	0.0	24,008.0	31,010.9
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	2,128.0	2,128.0
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
DOM	DOM	Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0
		Unrelated	2,476.9	310.5	0.0	300.3	4,968.4	8,056.1
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	150.3	150.3
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,441.6	7.5	0.0	0.0	4,648.6	8,097.7
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	9,373.1	4,302.1	0.0	0.0	26,082.9	39,758.1
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	7,671.5	0.0	0.0	0.0	2,968.8	10,640.3
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	734.6	1,319.6	110.0	0.0	3,671.6	5,835.8
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	816.1	0.0	0.0	0.0	1,295.6	2,111.7
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	6,589.2	0.0	0.0	0.0	2,304.0	8,893.2
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	260.2	1,067.5	0.0	0.0	5,620.3	6,948.0
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	349.6	226.5	0.0	67.3	3,479.1	4,122.5
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,300.0	0.0	0.0	0.0	20.0	1,320.0
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0
		Unrelated	36,471.1	10,778.3	110.0	367.6	81,345.6	129,072.6

Solar Project Developer and Transmission Owner Relationships

Table 12-48 shows the relationship between the project developer and transmission owner for all solar project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2021, by transmission owner and project status. Of the 5,880.3 solar project MW that have achieved in service or under construction status during this time period, 1,532.6 MW (26.1 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 861.2 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2021, 180.4 MW (20.9 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-48 Relationship between project developer and transmission owner for all solar project MW in the queue: December 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	100.0	34.7	0.0	0.0	165.0	299.7
		Unrelated	37,656.0	230.0	320.0	0.0	8,951.4	47,157.4
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	3,240.5	2.5	400.0	0.0	1,922.4	5,565.4
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	58.9	0.0	0.0	0.0	33.0	91.9
DOM	DOM	Related	3,465.4	896.4	445.6	0.0	251.9	5,059.3
		Unrelated	27,770.1	1,087.3	949.0	729.9	14,187.1	44,723.4
DUKE	DUKE	Related	50.0	0.0	0.0	0.0	56.4	106.4
		Unrelated	619.9	200.0	0.0	10.0	633.0	1,462.9
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,740.2	0.0	0.0	95.0	998.9	6,834.1
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	676.0	62.0	2.6	0.0	2,258.8	2,999.3
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	154.9	1.1	0.0	0.0	101.6	257.6
	COMED	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	11,800.6	0.0	0.0	0.0	3,496.2	15,296.8
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,868.3	123.0	249.6	202.0	2,590.9	5,033.8
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	108.3	3.3	0.0	0.0	78.4	190.0
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	215.1	2.5	0.0	0.0	441.6	659.3
First Energy	APS	Related	26.4	0.0	0.0	0.0	0.0	26.4
		Unrelated	5,594.3	112.3	38.2	208.4	2,651.6	8,604.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,839.3	0.0	0.0	70.0	1,903.5	7,812.8
	JCPLC	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	453.7	412.2	0.0	18.6	1,629.2	2,513.7
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	936.1	0.0	0.0	87.0	834.7	1,857.8
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,780.9	13.5	0.0	60.2	2,595.1	8,449.6
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	430.0	0.0	0.0	0.0	78.0	508.0
PPL	PPL	Related	124.8	0.0	0.0	0.0	0.0	124.8
		Unrelated	2,298.9	25.0	0.0	0.0	1,002.1	3,325.9
PSEG	PSEG	Related	0.0	134.3	5.2	0.0	40.9	180.4
		Unrelated	41.1	97.6	16.1	0.0	526.0	680.8
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	3,766.5	1,081.8	450.8	0.0	576.0	5,875.1
		Unrelated	111,283.2	2,372.2	1,975.5	1,481.0	46,913.2	164,025.1

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-49 shows the relationship between the project developer and transmission owner for all renewable hybrid project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2021, by transmission owner and project status. Of the 6.8 renewable hybrid project MW that have achieved in service or under construction status during this time period, 3.7 MW (53.9 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building hybrid projects in their own service territory. Of the 53.5 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2021, 3.7 MW (6.9 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-49 Relationship between project developer and transmission owner for all hybrid project MW in the queue: December 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	180.0	0.0	0.0	0.0	0.0	180.0
		Unrelated	11,760.5	0.0	3.2	0.0	3,360.8	15,124.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	338.9	0.0	0.0	0.0	0.0	338.9
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	37.5	0.0	0.0	0.0	0.0	37.5
DOM	DOM	Related	17.0	0.0	0.0	0.0	0.0	17.0
		Unrelated	7,236.8	0.0	0.0	0.0	2,114.9	9,351.7
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	50.0	0.0	0.0	0.0	0.0	50.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,626.3	0.0	0.0	0.0	1,004.0	3,630.3
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	213.0	0.0	0.0	0.0	14.5	227.5
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,484.8	0.0	0.0	0.0	629.9	3,114.7
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	170.0	0.0	0.0	0.0	0.0	170.0
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5.0	0.0	0.0	0.0	0.0	5.0
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,346.5	0.0	0.0	0.0	20.0	1,366.5
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,444.3	0.0	0.0	36.3	375.0	2,855.6
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	800.8	0.0	0.0	0.0	334.9	1,135.7
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	180.0	0.0	0.0	0.0	0.0	180.0
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	52.1	0.0	0.0	105.0	23.7	180.8
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	884.8	0.0	0.0	3.0	180.5	1,068.4
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	178.5	0.0	0.0	0.0	0.0	178.5
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	677.2	0.0	0.0	90.0	180.0	947.2
PSEG	PSEG	Related	0.0	1.1	2.6	0.0	0.0	3.7
		Unrelated	20.0	0.0	0.0	0.0	29.9	49.9
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	197.0	1.1	2.6	0.0	0.0	200.7
		Unrelated	31,506.9	0.0	3.2	234.3	8,268.1	40,012.4

Regional Transmission Expansion Plan (RTEP)[47]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Manager approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated purpose of the market efficiency analysis is: to determine which reliability based enhancements have economic benefit if accelerated; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. PJM identifies the economic benefit of proposed transmission projects based on production cost analyses.[48] PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over $50 million. PJM provides the review of a project with a projected cost of over $50 million using its own staff or outside consultants that are hired to assist in the review. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the cost/benefit ratio for the project. The cost/benefit ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission projects for years five through 15. This long-term proposal window takes place concurrently with the long-term proposal window for reliability projects.

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project was approved by the PJM Board.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. The 2014/2015 long term window was open from November 1, 2014, through February

47 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).

48 See PJM. "*PJM Regional Transmission Expansion Plan: 2019*," (February 29, 2020) <https://www.pjm.com/-/media/library/reports-notices/2019-rtep/2019-rtep-book-1.ashx>.

28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from November 1, 2016, through February 28, 2017. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project was approved by the PJM Board.

The fourth market efficiency cycle was performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on one internal and three interregional flowgates. PJM received 33 proposals from 10 entities. One project was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.[49]

The fifth market efficiency cycle was performed for the 2020/2021 RTEP long term window. The 2020/2021 RTEP long term window was open from November 11, 2020, through May 11, 2021. This window accepted proposals to address historical congestion on four internal flowgates. PJM received 24 proposals from seven entities. Final project selections were made in the fourth quarter of 2021. The four projects selected will be presented to the PJM Board for approval in February 2022.

49 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates. One proposal received provisional approval by the PJM Board, pending approval by the MISO Board.

The Cost/Benefit Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a market efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a cost/benefit ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market, but does not weight increases and decreases in benefits equally. The method for calculating energy market benefits and reliability pricing model benefits depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv.

The energy market benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in energy production costs and load energy payments.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project, including only those zones where the project reduced the load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but including only those zones where the project reduced the load energy payments.

In both the regional and subregional analysis, changes in zonal load energy payments are netted against changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone for purposes of determining whether a zone benefits from a proposed RTEP project. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value of the ARR rights with and without the RTEP project is evaluated based on changes in modeled CLMPs on the latest allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade and the value of the ARRs are assumed to match the forecasted CLMP differences on the ARR paths.

The Reliability Pricing Model (RPM) Benefit analysis is conducted using the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system wide total system capacity payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments.

The difference in the benefits calculation used in the regional and subregional cost/benefit threshold tests is related to how the direct costs of the transmission projects are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits.

There are significant issues with PJM's cost/benefit analysis. The current rules governing cost/benefit analysis of competing transmission projects do not accurately measure the relative costs and benefits of transmission projects. The current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used. The current rules explicitly ignore the increased zonal load costs that a project may create. The current rules do not account for the fact that the project costs are nonbinding estimates, are not subject to cost caps and may significantly exceed the estimated costs. These flaws have contributed to PJM approving market efficiency projects with forecasted benefits that do not exceed the forecasted costs.

The recent introduction of storage as transmission assets (SATA) raises a number of additional concerns about PJM's cost/benefit analysis. PJM's cost/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. Using a 15 year benefit horizon will exaggerate the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established. Without clear rules on how to allocate operational revenues and costs it is impossible to develop forecasted benefits and/or costs of a SATA project.

The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

The Transource Project

The Transource Project (Project 9A) is an example of a PJM approved market efficiency project that initially passed PJM's 1.25 cost/benefit threshold test despite having benefits, if accurately calculated, that were less than forecasted costs. This project also illustrates the risks of ignoring potential cost increases given that the costs included in the cost/benefit calculation are nonbinding estimates. The Transource Project was proposed in PJM's 2014/2015 RTEP long term window. PJM's 2014/2015 RTEP long term window was the first market efficiency cycle under Order 1000. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. The AP South Interface was one of the 12 identified flow gates listed in the 2014/15 RTEP Long Term Proposal Window Problem Statement.

A total of 41 market efficiency projects were proposed to address congestion on the AP South Transmission Interface. Transource Energy LLC, together with Dominion High Voltage, submitted a proposal referenced by PJM as Project 9A (or IEC or the Transource project) to address AP South related congestion.

Project 9A was considered a subregional project based on its voltage level, meaning that changes in forecasted system costs were not considered for purposes of estimating the cost/benefit ratios. Instead, only reductions in zonal load costs were considered as a benefit of the project. Any increases in zonal load costs were ignored in the analysis.

The initial study had a benefit to cost ratio of 2.48, with a capital cost of $340.6 million. The sum of the positive (energy cost reductions) effects was $1,188.07 million. The sum of negative effects (energy cost increases) was $851.67 million. The net actual benefit of the project in the study was therefore $336.40 million, not the $1,188.07 used in the study. Using the total benefits (positive and negative) to compare to the net present value of costs, the benefit to cost ratio was 0.70, not 2.48. The project should have been rejected on those grounds.

Subsequent studies of the 9A project have reduced its benefit/cost ratio as a result of increased costs, decreased congestion on the AP South Interface since 2014 and a reduction in peak load forecasts since 2015.

PJM's 2019 study using simulations for years 2017, 2021, 2024 and 2027 had a cost benefit ratio of 2.10 with a capital cost of $383.63 million. The sum of the positive (energy cost reductions) effects was $855.19 million, a reduction of $322 million (28.0 percent) from the initial study. The sum of negative effects (energy cost increases) was $827.34 million, a reduction of $27.86 million (3.3 percent) from the results of the initial study. The net actual benefit of the project in the 2019 study was $27.85 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was 0.07, not 2.10. The project should have been rejected on those grounds.

A portion of Project 9A in Pennsylvania was challenged in a proceeding at the Pennsylvania PUC. On May 20, 2021, the Pennsylvania PUC denied the Transource application to build in Pennsylvania based on failure to demonstrate need combined with negative economic and environmental effects.[50] Transource is appealing the decision at the state and federal level.[51]

On September 22, 2021, the PJM Board endorsed PJM's recommendation to suspend the Transource IEC (9A) Project, based on the rejection by the Pennsylvania PUC. Project 9A was removed from PJM's planning models pending future updates.[52]

While suspended, PJM is required by Schedule 6 of the Operating Agreement (OA) to "annually review the cost and benefits" of Board approved market efficiency projects that have not commenced construction or have not received state siting approval. Under Schedule 6,

50 See *Applications of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection–East and West Projects in portions of York and Franklin Counties*, Pennsylvania et al., Opinion and Order, Docket No. A-2017-2640195 et al. (May 20, 2021).

51 See *Transource Pennsylvania, LLC et a. v. Pennsylvania Public Utility Commission*, Docket No. 689 CD 2021 (Commonwealth of Pennsylvania Court); *Transource Pennsylvania LLC v. Gladys Brown Dutrieuille*, et al, Docket No. 21-2567 (USDC M.D. Pa.).

52 Nick Dumitriu, Principal Engineer, PJM Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (November 30, 2021) at 18 <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211130/20211130-item-02-market-efficiency-update.ashx>.

PJM's 2021 study showed a cost/benefit ratio of 1.00 with a capital cost of $453.71 million. The sum of the positive (energy cost reductions) effects was $452.4 million, a reduction of $735.7 million (-61.9 percent) from the initial study. The sum of negative effects (energy cost increases) was $452.4 million, a reduction of $399.3 million (46.9 percent) in the negative effects from the -$851.7 results of the initial study. The net benefit of the project in the 2021 study was -$159.8 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was -0.35, not 2.10. The project should be rejected on these grounds rather than simply suspended.

PJM MISO Interregional Market Efficiency Process (IMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.[53] The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM makes use of the cost/benefit analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members.

PJM and MISO conducted a two year interregional market efficiency project study in 2018/2019 and included the investigation of forward looking congestion on three market to market flowgates. Proposals were received during the 2018/2019 long term window, which was open from November 2, 2018, through March 15, 2019. PJM and MISO received 10 proposals from seven entities. As a result of this analysis, the RTOs recommended one IMEP project, the Bosserman to Trail Creek 138 kV Project.[54] The approved project has an in service cost of $24.7 million, and counting only PJM positive zonal benefits, a total present value of projected benefits of $69.2 million. Ignoring PJM zones with negative benefits (increased costs to load) the project has a calculated PJM cost/benefit ratio of 2.63. MISO, using both positive and negative zonal effects, calculated the projected benefits of the project to be $8.4 million. Based on the proportion of the calculated benefits, PJM is to be allocated 89.1 percent ($23.4 million) of the project costs and MISO is to be allocated 10.9 percent ($2.9 million) of the interregional costs. The PJM board approved the recommended project in December 2019. The MISO board approved the recommended project in September 2020.

Using a rational measure of benefits and costs, the Bosserman to Trail Creek 138 kV Project should not have been approved. Including the projected positive and negative benefits of the project to all PJM zones, the projected total benefits of the project drops from $69.2 million to -$68.1 million dollars. PJM analysis shows benefits to only one zone of $69.2 million, with the negative effect on all other zones of -$137.3 million. The resulting cost/benefit ratio would be -2.59. Even including the net MISO benefit of $8.4 million, the total projected benefit of the project would still be -$59.7 million dollars. Allocating the costs of the project based on the proportion of total regional benefit (-$68.1 million to PJM and $8.4 million to MISO) would have allocated 100 percent of the cost to MISO, resulting in a cost/benefit ratio of 0.32 to MISO, and a rejection of the project by MISO.

53 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

54 Analysis showed that no projects met the B/C criteria on two of the identified flowgates.

No interregional constraints were identified in either PJM or MISO's regional processes. Therefore, an IMEP study was not required during the 2020/2021 IMEP cycle.

PJM MISO Targeted Market Efficiency Process (TMEP)

PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than $20 million and must have estimated benefits, based on the projected congestion cost relief over a four year period, that exceed the expected installed capacity cost of the proposed project.[55] [56]

The benefit of a proposed TMEP project is calculated as the value of eliminating congestion on the affected constraint over a four year period. PJM and MISO calculate the estimated value of eliminating congestion by calculating the average congestion for the two prior years prior and multiplying by four.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits received by that RTO.[57] The proportion of benefits is calculated using the average shadow price of the constraint times the dfax to affected downstream buses times MW of load at the buses, which is effectively the proportion of congestion paid by the RTO. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of historical congestion on an initial set of 50 market to market flowgates. The causes of congestion on these flowgates were analyzed. If the historical congestion was a result of outages, or if the congestion was expected to be mitigated by planned upgrades already included in the PJM RTEP or MISO MTEP, then the flowgate was eliminated from consideration in the TMEP process. As a result of this analysis, potential short term upgrades were identified for 13 of the initial 50 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 13 flowgates and recommended five TMEP projects. The five projects address $59.0 million in historical congestion, with a calculated TMEP benefit of $99.6 million. The projects have a total cost of $20.0 million, with a 5.0 average cost/benefit ratio. PJM and MISO presented the five recommended projects to their boards in December 2017, and both boards approved all five projects.[58]

The second Targeted Market Efficiency Process analysis occurred in 2018 and included the investigation of historical congestion on an initial set of 61 market to market flowgates. As a result of this analysis, potential short term upgrades were identified for 20 of the initial 61 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 20 flowgates and recommended two TMEP projects. The two projects address $25.0 million in historical congestion, with a calculated TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average cost/benefit ratio. PJM and MISO presented the two recommended projects to their boards in December 2018, and both boards approved the projects.[59]

With only one additional year of historical information, and the fact that many of the same constraints were evaluated in the 2018 TMEP process, PJM and MISO did not conduct a TMEP study in 2019. As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020. PJM and MISO agreed to assess the impact of planned upgrades and congestion using an additional year of market data. As a result, PJM and MISO did not conduct a TMEP study in 2021.

55 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

56 On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process. See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, et al. (November 2, 2017).

57 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

58 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

59 See PJM. "*MISO PJM IPSAC*," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through the ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total cost of energy before and after the upgrade to all affected load. This measurement would include the change in expected LMP of all affected load before and after the upgrade, times the MW of load, plus the change in congestion dollars returned to the affected load before and after the upgrade. Congestion revenue returned to load is not a cost to the load, it is a credit against the overpayment of load payments relative to generation credits caused by the transmission constraint. Ignoring the return of congestion from ARRs/FTRs overstates the potential benefits of eliminating congestion through the TMEP upgrades, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

Supplemental Transmission Projects

Supplemental projects are asserted to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[60] Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan.

The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted in the Local Plan is the Transmission Owner's decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM's Regional Transmission Expansion Plan and are allocated 100 percent to the zone in which the transmission facilities are located. Supplemental Projects may displace projects that would have otherwise been implemented through the RTEP process.

Supplemental projects are currently exempt from the Order No. 1000 competitive process.[61] Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-5 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No. 890, there were transmission projects planned by transmission owners and included in the PJM planning models, that were not included in the totals shown in Figure 12-5, Table 12-50 and Table 12-51 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

60 See PJM. Planning. "Transmission Construction Status," (Accessed on December 31, 2021) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

61 FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

Figure 12-5 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through December 31, 2021

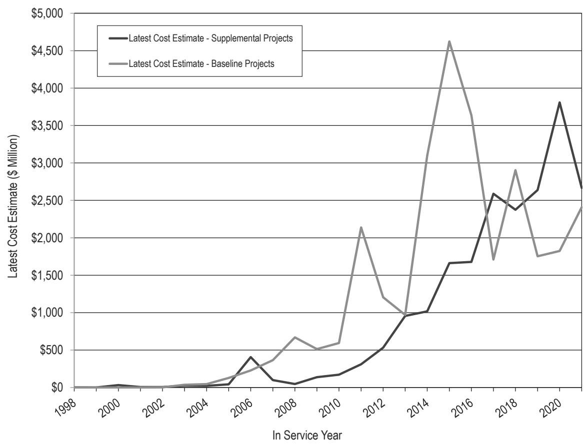


Table 12-50 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 770.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 174 for years 2008 through 2021 (post Order No. 890).

Table 12-50 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	2
2000	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0	0	0	0	0	0	0	0	11
2001	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	10
2003	3	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	0	2	0	40
2005	4	2	8	0	0	4	0	0	0	1	14	0	1	0	0	0	1	2	0	0	2	0	39
2006	4	2	5	0	0	6	0	0	0	0	9	0	1	0	0	0	0	1	0	2	1	0	31
2007	1	1	5	0	4	5	0	0	4	0	6	0	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	0	3	1	0	41
2009	3	1	6	0	1	8	0	0	3	3	5	0	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	7	0	3	4	0	0	6	3	0	0	1	2	0	0	2	0	0	3	5	0	42
2011	0	8	8	0	0	2	0	0	5	2	0	0	1	0	0	0	4	0	0	6	4	0	40
2012	0	5	6	4	1	2	0	7	3	16	1	0	2	0	0	0	1	0	0	5	11	0	64
2013	5	21	4	5	0	11	0	6	4	13	1	0	1	1	0	0	1	0	1	14	19	0	107
2014	2	31	2	8	2	14	0	5	6	18	3	2	2	0	0	0	1	2	0	9	16	0	123
2015	4	15	2	9	1	37	0	8	4	17	5	4	2	0	0	0	1	0	4	7	24	0	144
2016	6	17	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	30	0	147
2017	8	107	3	26	1	23	0	3	8	31	11	5	0	3	0	0	0	3	1	22	43	0	298
2018	10	143	3	13	1	20	0	14	3	22	6	4	0	0	0	0	2	0	1	20	26	0	288
2019	3	159	4	30	5	14	2	17	1	33	8	5	3	14	0	0	1	15	0	15	27	0	356
2020	5	123	4	33	6	12	5	14	1	29	2	6	10	18	0	0	3	35	1	17	22	0	346
2021	4	141	6	36	6	3	9	14	2	27	1	8	14	35	0	5	19	32	0	20	21	0	403
2022	2	284	6	46	2	9	5	5	1	36	4	5	14	56	0	0	6	39	1	24	21	0	566
2023	6	250	3	16	0	4	18	8	1	23	3	5	1	10	1	0	3	36	3	21	27	0	439
2024	6	161	0	10	0	4	11	2	0	11	3	3	5	29	0	0	0	39	2	16	10	0	312
2025	4	112	1	6	3	0	7	0	0	28	5	1	0	22	0	0	0	24	0	6	19	0	238
2026	5	19	0	1	8	1	0	2	0	18	2	2	1	1	0	0	0	0	0	15	7	0	82
2027	1	26	0	3	1	0	0	1	2	0	1	1	0	1	0	0	0	1	0	26	0	0	64
2028	0	16	0	0	0	0	0	1	1	0	1	2	0	0	0	0	0	0	0	2	0	0	23
2029	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	6
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
2031	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	94	1,650	112	264	50	224	57	113	58	351	160	55	61	194	1	5	53	237	17	269	346	0	4,371

Table 12-51 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 2,176.8 percent, from $64.6 million for years 1998 through 2007 (pre Order No. 890) to $1,470.8 million for years 2008 through 2021 (post Order No. 890).

Table 12-51 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.67	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.93
2006	$4.03	$309.70	$0.94	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.15
2007	$0.56	$2.06	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$9.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.82
2008	$2.36	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.60	$0.00	$0.00	$47.33
2009	$0.77	$0.90	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.67
2010	$0.00	$34.36	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.38	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$309.71	$0.00	$1,016.93
2015	$3.73	$237.45	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.56	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.36
2016	$74.54	$84.13	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$0.00	$86.40	$0.40	$7.80	$58.76	$744.18	$0.00	$1,677.44
2017	$66.28	$648.74	$8.60	$164.45	$0.09	$145.97	$0.00	$64.31	$3.62	$104.25	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
2018	$66.55	$817.94	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$631.25	$0.00	$2,374.10
2019	$64.30	$1,162.53	$11.97	$190.40	$76.55	$90.19	$0.30	$99.19	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,638.50
2020	$59.58	$782.03	$0.30	$112.78	$62.58	$78.09	$13.66	$86.86	$6.40	$258.32	$39.50	$25.61	$2.60	$23.70	$0.00	$0.00	$2.40	$74.50	$102.70	$215.29	$1,861.58	$0.00	$3,808.48
2021	$86.54	$936.09	$7.80	$206.84	$27.90	$125.70	$34.90	$158.79	$18.90	$77.24	$0.20	$28.14	$41.00	$144.39	$0.00	$4.40	$45.30	$72.36	$0.00	$196.23	$454.44	$0.00	$2,667.16
2022	$107.70	$1,749.90	$7.92	$295.00	$265.40	$118.40	$23.05	$38.25	$45.00	$331.96	$46.00	$11.18	$48.50	$155.24	$0.00	$0.00	$90.90	$93.73	$3.60	$283.30	$523.03	$0.00	$4,238.06
2023	$96.00	$1,986.49	$6.14	$194.68	$0.00	$25.40	$71.45	$64.32	$0.00	$141.11	$32.70	$29.69	$6.80	$78.90	$51.90	$0.00	$201.80	$86.00	$737.50	$362.34	$975.50	$0.00	$5,148.72
2024	$81.81	$1,405.93	$0.00	$177.53	$0.00	$212.40	$78.70	$17.64	$0.00	$239.57	$47.20	$30.55	$38.50	$186.66	$0.00	$0.00	$0.00	$93.30	$38.50	$252.00	$305.81	$0.00	$3,206.10
2025	$56.79	$943.99	$60.00	$199.70	$144.10	$0.00	$34.85	$0.00	$0.00	$385.07	$78.72	$1.05	$0.00	$115.20	$0.00	$0.00	$0.00	$51.00	$0.00	$127.00	$457.90	$0.00	$2,655.37
2026	$95.50	$201.10	$0.00	$19.60	$336.00	$67.00	$0.00	$13.30	$0.00	$328.40	$16.11	$21.90	$16.00	$26.40	$0.00	$0.00	$0.00	$0.00	$0.00	$387.80	$215.80	$0.00	$1,744.91
2027	$17.13	$377.53	$0.00	$389.30	$118.00	$0.00	$0.00	$23.97	$160.00	$0.00	$6.10	$13.74	$0.00	$10.00	$0.00	$0.00	$0.00	$138.00	$0.00	$582.41	$0.00	$0.00	$1,836.18
2028	$0.00	$365.44	$0.00	$0.00	$0.00	$0.00	$0.00	$17.90	$30.40	$0.00	$0.00	$30.78	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$51.00	$0.00	$0.00	$495.52
2029	$0.00	$0.00	$0.00	$0.00	$231.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$96.60	$0.00	$0.00	$327.60
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$91.90	$0.00	$0.00	$91.90
2031	$0.00	$0.00	$0.00	$80.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$80.00
2032	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2033	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$200.00	$0.00	$0.00	$0.00	$0.00	$200.00
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$911.28	$12,666.51	$228.31	$2,369.73	$1,353.06	$1,848.53	$256.91	$722.00	$514.35	$2,669.39	$616.14	$231.58	$174.05	$828.54	$51.90	$4.40	$752.30	$908.52	$1,103.00	$3,664.77	$9,386.17	$0.00	$41,261.44

The MMU recommends, to increase the role of competition, that the exemption of supplemental from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[62]

The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects.

62 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project types include:

- **Immediate Need Exclusion.** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is defined to be infeasible and such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[63] On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission's directives under Order 1000.[64] Some supplemental projects are in this category.
- **Below 200kV.** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[65] Some supplemental projects are in this category.
- **Substation Equipment.** Due to identification of the limiting element(s) as substation equipment, such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[66] Some supplemental projects are in this category.

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition for any of these exclusion categories.

63 See OA Schedule 6 § 1.5.8(m).
64 169 FERC ¶ 61,054 (2019).
65 See OA Schedule 6 § 1.5.8(n).
66 See OA Schedule 6 § 1.5.8(p).

Comparative Cost Framework

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[67]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. The analysis performed under the new process was insufficient and did not follow the process defined in the PJM manual.[68] The existing proposal templates do not provide enough information to adequately perform a financial analysis. The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee is currently considering whether storage devices should be included in the RTEP process as transmission assets.[69]

Transmission and generation have, and have always had, a symbiotic relationship in the provision of wholesale power. Transmission needs generation to function and generation needs transmission to function. Transmission can substitute for generation at the margin and generation can substitute for transmission at the margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on

67 170 FERC ¶ 61,243 (2020).
68 See "PJM Manual 14F: Competitive Planning Process," Rev. 8 (November 17, 2021).
69 See PJM. "*Storage As A Transmission Asset: Problem / Opportunity Statement,*" <https://pjm.com/-/media/committees-groups/committees/pc/2020/20200605-special/20200605-item-02a-storage-as-a-transmission-asset-problem-statement-clean.ashx>.

competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost-of-service recovery through AEP's formula rates.[70] AEP's Middle Creek energy storage project was a proposed battery storage device that would discharge energy to serve retail load at the Middle Creek substation in the event of a transmission outage. On December 21, 2020, the Commission ruled that the Middle Creek energy storage project did not perform a transmission function, and was ineligible to recover its costs through formula rates.[71]

Storage devices like batteries that are defined to be part of PJM markets should not be treated as transmission assets. The MMU recommends that storage resources not be includable as transmission assets for any reason.

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[72]

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

In 2021, the PJM Board approved a net change of $1.11 billion in transmission upgrades. As of December 31, 2021, the PJM Board had approved $38.9 billion in transmission system enhancements since 1999. On February 22, 2021, the PJM Board authorized an additional $349.8 million in transmission upgrades and additions. On April 23, 2021, the PJM Board authorized an additional $330.7 million in transmission upgrades and additions. On July 30, 2021, the PJM Board authorized an additional $221.7 million in transmission upgrades and additions. On September 23, 2021, the PJM Board authorized an additional $77.0 million in transmission upgrades and additions. On December 2, 2021, the PJM Board authorized an additional $134.7 million in transmission upgrades and additions.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions.

If a QTU that was cleared in a Base Residual Auction (BRA) or Incremental Auction (IA) is not completed by the start of the Delivery Year, the submitting party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of December 31, 2021, no QTUs have cleared a BRA or IA.

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether

70 See *AEP*, Docket No. EL20-58 (July 22, 2020).
71 173 FERC ¶ 61,264 (2020).
72 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

an alternative just and reasonable ex ante cost allocation method could be established for any such category of projects."[73] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[74]

The issues identified in the complaints and at the technical conference included: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

On February 20, 2020, the Commission issued an Order denying rehearing requests.[75] The Commission found that PJM's solution based dfax method for regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable.

It is clear that the allocation issues are difficult. Nonetheless, the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed.

As an example, the use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

Transmission Line Ratings

Transmission line ratings, and more broadly transmission facility ratings, are the metric for the ability of transmission lines to transmit power from one point to another. Transmission line ratings have significant and frequently underappreciated impacts on competitive wholesale power markets like PJM. These include direct impacts on energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the interconnection costs for new power plants. The impact of transmission facility ratings on markets is a function both of the line ratings directly and the use of those ratings by the RTO/ISO.

Congestion payments by load result when lower cost generation is not available to meet all the load in an area as a result of limits on the transmission system. When higher cost local generation is needed to meet part of the local load because of transmission limits, 100 percent of the local load pays the higher price while only the local generation receives the higher price. The difference between what the load pays and generators receive is congestion. Since 2008, congestion costs in PJM have ranged from $0.5 billion to $2.05 billion per year. Congestion costs were significantly higher during extreme winter weather conditions such as January 2014, when the congestion costs in PJM were $825.1 million for one month.[76]

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors.

73 153 FERC ¶ 61,245 at P 35 (2015).
74 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
75 170 FERC ¶ 61,122 (2020).
76 See the *2018 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses.

The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. Transmission penalty factors were fully implemented in PJM pricing effective February 1, 2019. The default transmission penalty factor is $2,000 per MWh.

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, generally results in at least a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers often reduce the limits.[77] Violation of these reduced line ratings results in penalty factors setting prices. In 2021, there were 170,067 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly eight percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit. In 2021, the average shadow price of transmission constraints when the line limit was violated was nearly 8.8 times higher than when the transmission constraint was binding at its limit.[78]

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was $200.30 per MW-day. The clearing price for the EMAAC LDA was $165.73 per MW-day.[79]

Transmission line ratings for a given transmission facility vary by the duration of the power flow, by ambient temperatures, by wind speed and by other conditions. Transmission lines can operate with higher loads for shorter periods of time. This is significant when a contingency is expected to last for only a short period. The transmission line rating can mean the difference between substantial congestion costs and no congestion costs. The transmission line rating can mean the difference between a transmission penalty factor and no penalty factor.

In PJM, transmission owners use a range of ratings by duration.[80] PJM requires transmission owners to provide thermal ratings under normal operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings. In PJM, transmission owners have substantial discretion in the approach to line ratings. [81]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current

77 See "Transmission Constraint Control Logic and Penalty Factors," presented at May 10, 2018 meeting of the Markets Implementation Committee Special Session Transmission Constraint Penalty Factors at p14. <https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-03-transmission-constraint-penalty-factor-education.ashx>.

78 See the *2020 State of the Market Report for PJM*, Volume II, Section 3: Energy Market.

79 See the "Analysis of the 2021/2022 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

80 See "PJM Manual 3: Transmission Operations," Rev. 60 (November 17, 2021) § 2.1.1, at p 27.

81 PJM presentation to the Planning Committee (PC) (May 3, 2018) "Transmission Owner Ratings Development and Reporting in PJM" ("There are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check.") at 24.

line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented.

Line ratings determine the actual value of transmission in market operations. Yet the methods for defining line ratings remain opaque and vary significantly across transmission owners. Under defining line ratings results in over building transmission. Over defining line ratings results in less reliability than planned for. Dynamic line ratings are essential to reflect the actual availability of transmission in real time as ambient conditions change. Ensuring that system operators have accurate information about line ratings, including a wide range of line ratings by duration of load, are essential to ensure that all market participants receive the maximum value from the investment in the transmission system.

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings and implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when relevant.[82] The line rating methods should be public and fully transparent.

The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.[83] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

Order No. 881, issued December 16, 2021, requires: implementation by transmission providers of ambient-adjusted ratings on transmission lines; implementation by RTOs/ISOs of the systems and procedures necessary for hourly ratings updates; use of uniquely determined emergency ratings; sharing transmission line ratings and transmission line rating methods with RTOs/ISOs and market monitors; and maintenance of a database of transmission line ratings and transmission line rating methods on OASIS or other password-protected website. Order 881 did not require the use of dynamic line ratings based on an insufficient record.[84] But on February 17, 2022, in Docket No. AD22-5, FERC issued a notice of inquiry addressing the DLR issues.[85]

Dynamic Line Ratings (DLR) and GETs

For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real time prices are based on actual current line ratings. The relevant real time conditions include ambient air temperature, wind speeds, solar heating, transmission line tension, and transmission line sag. The widespread adoption of dynamic line ratings should be pursued. The adoption of dynamic line ratings does not require the exorbitant incentives proposed by some. Dynamic line rating technology and other Grid Enhancing Technology (GET) should be subject to competition and the costs of implementation should be capped at the costs that would result from the current cost of service method applied to transmission owners. The proposal that providers of GET should receive a share of forecast benefits is not consistent with competition, would pay rates of return many multiples of market rates of return and suffers from the same intractable problem of defining speculative benefits for long periods.

82 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee. <https://www.pjm.com/-/media/committees-groups/committees/pc/20180503/20180503-item-13-to-ratings-process-and-reporting.ashx>.

83 *See* the *2018 State of the Market Report for PJM*, Volume II, Section 2: Recommendations.f

84 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at PP 25, 254 (2021) ("Order No. 881")

85 *Implementation of Dynamic Line Ratings*, Notice of Inquiry, 178 FERC ¶ 61,110 (2022).

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[86] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[87] The specific timeline is shown in Table 12-53.[88]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the 2020/2021 planning period and the first seven months of the 2021/2022 planning period, regardless of when they were initially submitted.[89] The outage data for the day-ahead market are for outages scheduled to occur from 2015 through 2021.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[90] Table 12-52 shows that 74.8 percent of requested outages were planned for less than or equal to five days and 9.9 percent of requested outages were planned for greater than 30 days in the first seven months of 2021/2022 planning period. Table 12-52 also shows that 78.0 percent of the requested outages were planned for less than or equal to five days and 7.6 percent of requested outages were planned for greater than 30 days in the 2020/2021 planning period.

Table 12-52 Transmission facility outage request summary by planned duration: June 2020 through December 2021

	2020/2021 (12 months)		2021/2022 (7 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,125	78.0%	8,039	74.8%
>5 & <=30	2,969	14.4%	1,647	15.3%
>30	1,578	7.6%	1,067	9.9%
Total	20,672	100.0%	10,753	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-53.[91]

The purpose of the rules defined in Table 12-53 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and PJM can accurately model market conditions.[92]

Table 12-53 Transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	Received Status
<=5	Before the first of the month one month prior to the starting month of the outage	On Time
	After or on the first of the month one month prior to the starting month of the outage	Late
> 5 & <=30	Before the first of the month six months prior to the starting month of the outage	On Time
	After or on the first of the month six months prior to the starting month of the outage	Late
>30	The earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	Late

86 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).
87 See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).
88 See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).
89 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active.
90 *Id.* at 70.
91 See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).
92 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

Table 12-54 shows a summary of requests by received status. In the first seven months of 2021/2022 planning period, 43.6 percent of outage requests received were late. In the 2020/2021 planning period, 41.4 percent of outage requests received were late.

Table 12-54 Transmission facility outage requests by received status: June 2020 through December 2021

	2020/2021 (12 months)				2021/2022 (7 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,912	6,213	16,125	38.5%	4,766	3,273	8,039	40.7%
>5 & <=30	1,577	1,392	2,969	46.9%	897	750	1,647	45.5%
>30	632	946	1,578	59.9%	406	661	1,067	61.9%
Total	12,121	8,551	20,672	41.4%	6,069	4,684	10,753	43.6%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[93]

Outages with emergency status will be approved even if submitted late after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[94] Table 12-55 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first seven months of 2021/2022 planning period, 13.0 percent were for emergency outages. Of all outage requests scheduled to occur in the 2020/2021 planning period, 12.2 percent were for emergency outages.

Table 12-55 Transmission facility outage requests by emergency: June 2020 through December 2021

	2020/2021 (12 months)				2021/2022 (7 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,821	14,304	16,125	11.3%	1,020	7,019	8,039	12.7%
>5 & <=30	451	2,518	2,969	15.2%	196	1,451	1,647	11.9%
>30	251	1,327	1,578	15.9%	184	883	1,067	17.2%
Total	2,523	18,149	20,672	12.2%	1,400	9,353	10,753	13.0%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[95]

After PJM determines that a late request may cause congestion, PJM informs the transmission owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-56 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first seven months of 2021/2022 planning period, 6.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.2 percent (23 out of 711) were denied by PJM in the first seven months of 2021/2022 planning period and 19.7 percent (140 out of 711) were cancelled (Table 12-58). Of all outage requests submitted to occur in the 2020/2021 planning period, 6.3 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 1.6 percent (21 out of 1,296) were denied by PJM in the 2020/2021 planning period and 19.4 percent (251 out of 1,296) were cancelled (Table 12-58).

93 See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).

94 PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).

95 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 14 (Jan. 27, 2021).

Table 12-56 Transmission facility outage requests by congestion: June 2020 through December 2021

	2020/2021 (12 months)				2021/2022 (7 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	945	15,180	16,125	5.9%	509	7,530	8,039	6.3%
>5 & <=30	246	2,723	2,969	8.3%	127	1,520	1,647	7.7%
>30	105	1,473	1,578	6.7%	75	992	1,067	7.0%
Total	1,296	19,376	20,672	6.3%	711	10,042	10,753	6.6%

Table 12-57 shows the outage requests summary by received status, congestion status and emergency status. In the first seven months of 2021/2022 planning period, 30.8 percent of requests were submitted late and were nonemergency while 1.3 percent of requests (135 out of 10,753) were late, nonemergency, and expected to cause congestion. In the 2020/2021 planning period, 29.3 percent of request were submitted late and were nonemergency while 1.0 percent of requests (203 out of 20,671) were late, nonemergency, and expected to cause congestion.

Table 12-57 Transmission facility outage requests by received status, emergency and congestion: June 2020 through December 2021

		2020/2021 (12 months)				2021/2022 (7 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	71	2,415	2,486	12.0%	33	1,340	1,373	12.8%
	Non Emergency	203	5,862	6,065	29.3%	135	3,176	3,311	30.8%
On Time	Emergency	2	35	37	0.2%	3	24	27	0.3%
	Non Emergency	1,020	11,064	12,084	58.5%	540	5,502	6,042	56.2%
Total		1,296	19,376	20,672	100.0%	711	10,042	10,753	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[96] Table 12-58 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-58. Table 12-58 shows that of all the outage requests that were expected to cause congestion, 3.2 percent (23 out of 711) were denied by PJM in the first seven months of 2021/2022 planning period, 66.7 percent were complete and 19.7 percent (140 out of 711) were cancelled. Of all the outage requests that were expected to cause congestion, 1.6 percent (21 out of 1,296) were denied by PJM in the 2020/2021 planning period, 72.1 percent were complete and 19.4 percent (251 out of 1,296) were cancelled.

Table 12-58 Transmission facility outage requests by processed status: June 2020 through December 2021

		2020/2021 (12 months)						2021/2022 (7 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	5	63	2	1	71	88.7%	3	29	0	1	33	87.9%
	Non Emergency	33	147	10	10	203	72.4%	23	90	7	12	135	66.7%
On Time	Emergency	0	2	0	0	2	100.0%	2	1	0	0	3	33.3%
	Non Emergency	213	722	68	10	1,020	70.8%	112	354	62	10	540	65.6%
Total		251	934	80	21	1,296	72.1%	140	474	69	23	711	66.7%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[97] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-58 shows that in the 2020/2021 planning period, 203 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM manuals. The

96 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).
97 OA Schedule 1 § 1.9.2.

MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-59 is a summary of all the outage requests planned for the 2020/2021 planning period and the first seven months of 2021/2022 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the first seven months of 2021/2022 planning period, 30.7 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.6 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2020/2021 planning period, 30.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-59 Rescheduled and cancelled transmission outage requests: June 2020 through December 2021

	2020/2021 (12 months)					2021/2022 (7 months)				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	16,125	3,537	21.9%	2,257	14.0%	8,039	1,753	21.8%	1,190	14.8%
>5 & <=30	2,969	1,674	56.4%	202	6.8%	1,646	873	53.0%	110	6.7%
>30	1,578	1,029	65.2%	81	5.1%	1,068	673	63.0%	50	4.7%
Total	20,672	6,240	30.2%	2,540	12.3%	10,753	3,299	30.7%	1,350	12.6%

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as On Time or Late.

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[98] This rule allows a TO to reschedule within the same month with very little notice.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[99] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

The MMU recommends that PJM reevaluate all transmission outage tickets as On Time or Late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-53) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

98 PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).

99 *Id.*

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-60 shows equipment outages by the equipment instead of by outage request.

Table 12-60 shows that there were 7,622 transmission equipment planned outages in the first seven months of 2021/2022 planning period, of which 1,042 or 13.7 percent were longer than 30 days, and of which 91 or 1.2 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-60 Transmission equipment outages: June 2020 through December 2021

		2020/2021 (12 months)		2021/2022 (7 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,380	10.8%	951	12.5%
	Yes	239	1.9%	91	1.2%
<= 30		11,134	87.3%	6,580	86.3%
Total		12,753	100.0%	7,622	100.0%

Table 12-61 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[100] The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests was appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first seven months of 2021/2022 planning period, within effective duration greater than a month and shorter than two months, there were 33 outages with a combined duration longer than 30 days.

Table 12-61 Transmission equipment outages by effective duration: June 2020 through December 2021

	2020/2021 (12 months)		2021/2022 (7 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	2	0.8%	5	5.5%
>31 & <=62	23	9.6%	33	36.3%
>62 & <=93	18	7.5%	14	15.4%
>93	196	82.0%	39	42.9%
Total	239	100.0%	91	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR Auctions. The purpose of the rules governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and PJM can accurately model market conditions.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[101]

100 A transmission facility is modeled as equipment in the EMS model. Equipment has three identifiers: location (B1), voltage level (B2) and equipment name (B3). The types of equipment include, for example, lines, transformers, and capacitors. There can be multiple outage requests associated with the same equipment.

101 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

In the first seven months of 2021/2022 planning period, 278 outage requests were included in the annual FTR market outage list and 10,475 outage requests were not included.[102] In the 2020/2021 planning period, 321 outage requests were included in the annual FTR market outage list and 20,351 outage requests were not included. Table 12-62, Table 12-63, Table 12-64 and Table 12-65 show the summary information on the modeled outage requests and Table 12-66 and Table 12-67 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-62 shows that 30.2 percent of the outage requests modeled in the Annual FTR Market for the first seven months of 2021/2022 planning period had a planned duration of less than two weeks and that 18.3 percent of the outage requests (51 out of 278) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 27.4 percent of the outage requests modeled in the Annual FTR Market for the 2020/2021 planning period had a planned duration of less than two weeks and that 16.5 percent of the outage requests (53 out of 321) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-62 Annual FTR market modeled transmission facility outage requests by received status: June 2020 through December 2021

	2020/2021 (12 months)				2021/2022 (7 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	76	12	88	27.4%	73	11	84	30.2%
>=2 weeks & <2 months	88	13	101	31.5%	84	13	97	34.9%
>=2 months	104	28	132	41.1%	70	27	97	34.9%
Total	268	53	321	100.0%	227	51	278	100.0%

Table 12-63 shows the annual FTR market modeled outage requests summary by emergency status and received status. None of the annual FTR market modeled outages expected to occur in the first seven months of 2021/2022 planning period were emergency outages. Two of the modeled outages expected to occur in the 2020/2021 planning period were emergency outages.

Table 12-63 Annual FTR market modeled transmission facility outage requests by emergency: June 2020 through December 2021

		2020/2021 (12 months)				2021/2022 (7 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	76	76	100.0%	0	73	73	100.0%
	>=2 weeks & <2 months	0	88	88	100.0%	0	84	84	100.0%
	>=2 months	0	104	104	100.0%	0	70	70	100.0%
	Total	0	268	268	100.0%	0	227	227	100.0%
Late	<2 weeks	2	10	12	83.3%	0	11	11	100.0%
	>=2 weeks & <2 months	0	13	13	100.0%	0	13	13	100.0%
	>=2 months	0	28	28	100.0%	0	27	27	100.0%
	Total	2	51	53	96.2%	0	51	51	100.0%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-64 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first seven months of 2021/2022 planning period and submitted late, 17.6 (9 out of 51) was expected to cause congestion. Overall, of all the annual FTR market modeled outages expected to occur in the 2020/2021 planning period and submitted late, 9.4 percent (5 out of 53) were expected to cause congestion.

102 PJM's treatment of transmission outages in the FTR models is discussed in the *2021 State of the Market Report for PJM*: Section 13: FTRs and ARRs: Supply and Demand.

Table 12-64 Annual FTR market modeled transmission facility outage requests by congestion: June 2020 through December 2021

		2020/2021 (12 months)				2021/2022 (7 months)			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	17	59	76	22.4%	17	56	73	23.3%
	>=2 weeks & <2 months	19	69	88	21.6%	27	57	84	32.1%
	>=2 months	17	87	104	16.3%	12	58	70	17.1%
	Total	53	215	268	19.8%	56	171	227	24.7%
Late	<2 weeks	2	10	12	16.7%	1	10	11	9.1%
	>=2 weeks & <2 months	1	12	13	7.7%	5	8	13	38.5%
	>=2 months	2	26	28	7.1%	3	24	27	11.1%
	Total	5	48	53	9.4%	9	42	51	17.6%

Table 12-65 shows that 18.6 percent of outage requests modeled in the annual FTR market for the first seven months of 2021/2022 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 25.7 percent for the 2020/2021 planning period. Table 12-65 also shows that 16.5 percent of outages requests modeled in the Annual FTR Market for the first seven months of 2021/2022 planning period and with a duration of two months or longer were cancelled, compared to 17.4 percent for the 2020/2021 planning period.

Table 12-65 Annual FTR market modeled transmission facility outage requests by processed status: June 2020 through December 2021

		2020/2021 (12 months)		2021/2022 (7 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	5	5.7%	13	15.5%
	Approved	0	0.0%	0	0.0%
	Cancelled	27	30.7%	24	28.6%
	Active	0	0.0%	0	0.0%
	Completed	56	63.6%	47	56.0%
	Total	88	100.0%	84	100.0%
>=2 weeks & <2 months	In Progress	7	6.9%	17	17.5%
	Approved	1	1.0%	1	1.0%
	Cancelled	26	25.7%	18	18.6%
	Active	0	0.0%	2	2.1%
	Completed	67	66.3%	59	60.8%
	Total	101	100.0%	97	100.0%
>=2 months	In Progress	14	10.6%	13	13.4%
	Approved	0	0.0%	0	0.0%
	Cancelled	23	17.4%	16	16.5%
	Active	3	2.3%	19	19.6%
	Completed	92	69.7%	49	50.5%
	Total	132	100.0%	97	100.0%
Total Cancelled		76	23.7%	58	20.9%
Grand Total		321		278	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first seven months of 2021/2022 planning period, 278 outage requests were modeled and 10,475 outage requests were not modeled in the Annual FTR Market. In the 2020/2021 planning period, 321 outage requests were modeled and 20,351 outage requests were not modeled in the Annual FTR Market.

Table 12-66 shows that 3.8 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date for the first seven months of 2021/2022 planning period compared to 8.2 percent in the 2020/2021 planning period.

Table 12-66 Transmission facility outage requests not modeled in Annual FTR Auction: June 2020 through December 2021

	2020/2021 (12 months)						2021/2022 (7 months)					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,997	8,610	81.2%	237	6,784	96.6%	1,739	3,419	66.3%	167	3,526	95.5%
>=2 weeks & <2 months	708	305	30.1%	154	809	84.0%	482	69	12.5%	111	442	79.9%
>=2 months	214	19	8.2%	194	320	62.3%	128	5	3.8%	173	214	55.3%
Total	2,919	8,934	75.4%	585	7,913	93.1%	2,349	3,493	59.8%	451	4,182	90.3%

Table 12-67 shows that 93.9 percent of late outage requests that were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date, and were active or completed in the first seven months of 2021/2022 planning period. It also shows that 91.6 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were active or completed in the 2020/2021 planning period.

Table 12-67 Late transmission facility outage requests: June 2020 through December 2021

	2020/2021 (12 months)			2021/2022 (7 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,880	6,784	86.7%	3,056	3,526	86.7%
>=2 weeks & <2 months	707	809	87.4%	388	442	87.8%
>=2 months	293	320	91.6%	201	214	93.9%
Total	6,880	7,913	86.9%	3,645	4,182	87.2%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent those transmission outages from being submitted late. The MMU recommends that PJM modify the rules to eliminate the approval of outage requests submitted or rescheduled after the opening of bidding in the Annual FTR Auction.

Monthly FTR Market

When determining transmission outages to be modeled in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations less than or equal to five days. PJM exercises significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[103] Table 12-68 and Table 12-69 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-70 and Table 12-71 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

103 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

Table 12-68 shows that on average, 34.4 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the first seven months of 2021/2022 planning period. On average, 29.7 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2020/2021 planning period.

Table 12-68 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2020 through December 2021

	2020/2021				2021/2022			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	215	101	316	32.0%	209	116	325	35.7%
Jul	96	71	167	42.5%	103	85	188	45.2%
Aug	118	81	199	40.7%	125	81	206	39.3%
Sep	468	140	608	23.0%	363	147	510	28.8%
Oct	596	176	772	22.8%	480	192	672	28.6%
Nov	486	185	671	27.6%	454	205	659	31.1%
Dec	324	130	454	28.6%	325	153	478	32.0%
Jan	224	64	288	22.2%				
Feb	211	116	327	35.5%				
Mar	429	142	571	24.9%				
Apr	477	174	651	26.7%				
May	412	180	592	30.4%				
Average	338	130	468	29.7%	294	140	434	34.4%

Table 12-69 shows that on average, 16.6 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first seven months of 2021/2022 planning period. On average, 18.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2020/2021 planning period.

Table 12-69 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2020 through December 2021

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2020/2021	Jun	27	5	7	48	1	75	153	316	15.2%
	Jul	9	16	4	22	0	73	43	167	13.2%
	Aug	22	2	4	26	0	71	74	199	13.1%
	Sep	65	0	19	114	0	195	215	608	18.8%
	Oct	67	4	17	161	2	208	313	772	20.9%
	Nov	52	1	42	151	0	160	265	671	22.5%
	Dec	31	1	7	97	0	75	243	454	21.4%
	Jan	39	1	6	46	0	79	117	288	16.0%
	Feb	36	0	11	52	0	115	113	327	15.9%
	Mar	73	0	11	92	0	175	220	571	16.1%
	Apr	53	0	7	111	0	215	265	651	17.1%
	May	38	2	12	92	0	122	326	592	15.5%
	Average	43	3	12	84	0	130	196	468	18.0%
2021/2022	Jun	35	2	10	55	0	76	147	325	16.9%
	Jul	15	2	4	26	0	76	65	188	13.8%
	Aug	24	1	4	25	0	86	66	206	12.1%
	Sep	56	2	15	89	0	176	172	510	17.5%
	Oct	56	7	21	120	0	216	252	672	17.9%
	Nov	47	3	15	108	0	182	304	659	16.4%
	Dec	32	2	8	82	0	95	259	478	17.2%
	Average	38	3	11	72	0	130	181	434	16.6%

Table 12-70 shows that on average, 8.7 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first seven months of 2021/2022 planning period, compared to 9.7 percent in the 2020/2021 planning period. On average, 62.8 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first seven months of 2021/2022 planning period, compared to 65.5 percent in the 2020/2021 planning period.

Table 12-70 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2020 through December 2021

	2020/2021						2021/2022					
	On Time			Late			On Time			Late		
	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
Jun	798	105	11.6%	348	775	69.0%	778	85	9.8%	312	624	66.7%
Jul	430	90	17.3%	271	605	69.1%	349	69	16.5%	272	501	64.8%
Aug	437	75	14.6%	262	617	70.2%	371	43	10.4%	262	464	63.9%
Sep	1,061	87	7.6%	272	641	70.2%	943	96	9.2%	322	611	65.5%
Oct	1,187	75	5.9%	362	617	63.0%	1,043	69	6.2%	386	662	63.2%
Nov	961	74	7.1%	354	580	62.1%	867	43	4.7%	413	514	55.4%
Dec	737	69	8.6%	390	587	60.1%	681	26	3.7%	345	520	60.1%
Jan	595	84	12.4%	275	457	62.4%						
Feb	583	57	8.9%	275	575	67.6%						
Mar	1,346	81	5.7%	306	626	67.2%						
Apr	1,372	116	7.8%	383	645	62.7%						
May	1,189	108	8.3%	361	601	62.5%						
Average	891	85	9.7%	322	611	65.5%	719	62	8.7%	330	557	62.8%

Table 12-71 shows that on average, 70.2 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and complete in the first seven months of 2021/2022 planning period, compared to 71.2 percent in the 2020/2021 planning period.

Table 12-71 Late transmission facility outage requests: June 2020 through December 2021

	2020/2021			2021/2022		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	564	775	72.8%	429	624	68.8%
Jul	436	605	72.1%	371	501	74.1%
Aug	447	617	72.4%	307	464	66.2%
Sep	436	641	68.0%	408	611	66.8%
Oct	419	617	67.9%	470	662	71.0%
Nov	392	580	67.6%	347	514	67.5%
Dec	440	587	75.0%	402	520	77.3%
Jan	341	457	74.6%			
Feb	390	575	67.8%			
Mar	440	626	70.3%			
Apr	475	645	73.6%			
May	437	601	72.7%			
Average	435	611	71.2%	391	557	70.2%

Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the day-ahead energy market so that market participants can understand market conditions and PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am.[104]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is available to market participants. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential impact on markets. If the three sets of outages differ, there is a potential negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

For example for the operating day of May 5, 2018, Figure 12-6 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage requests included in both sets of outage; there were 128 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

104 PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).

Figure 12-6 Illustration of day-ahead market analysis: May 5, 2018

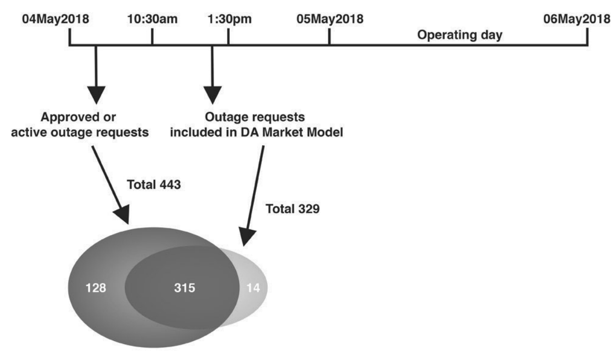


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-7 Approved or active outage requests: 2015 through 2021

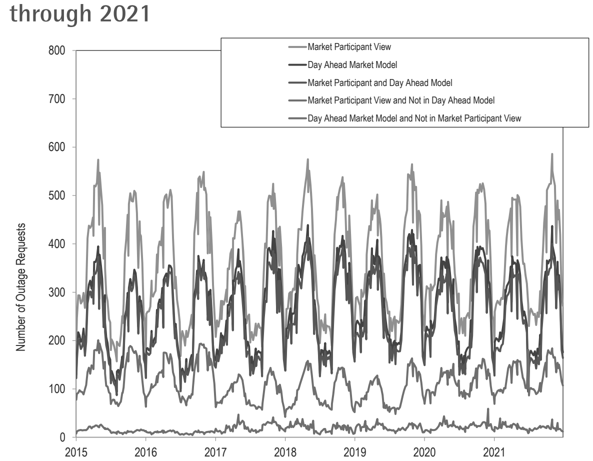


Figure 12-8 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-8 Day-ahead market model outages: 2015 through 2021

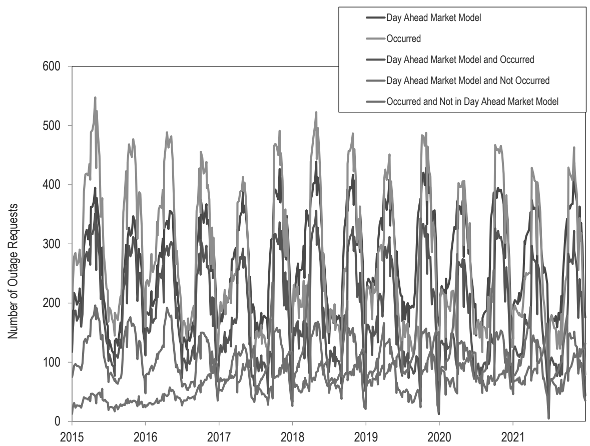


Figure 12-9 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-9 Approved or active outage requests: 2015 through 2021

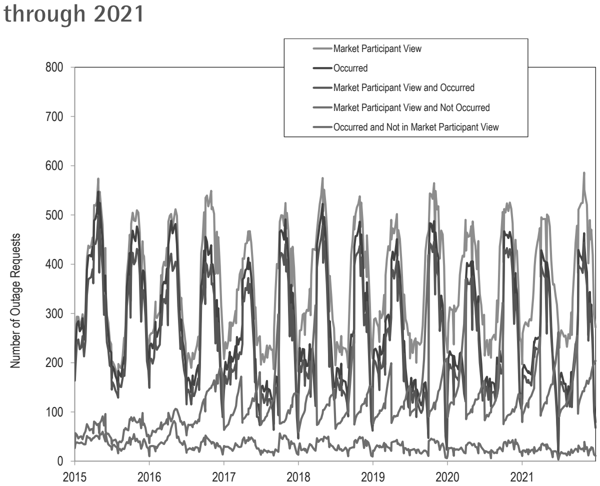


Figure 12-7, Figure 12-8, and Figure 12-9 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or approved outages available to day-ahead market participants are more consistent with the outages that actually occurred in real time than with the outages included in the day-ahead market model.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, but when there are transmission constraints, load pays the high local price for all generation, including the low cost generation serving part of that load. The low cost generation receives payment only for its low local price and does not receive the payment made by load for the output of the low cost generation at the high local price. The result is that load pays the correct local price but pays too much in total for energy because it is paying more for the low cost generation than the low cost generation receives. Load pays the difference between the high local price and the low local price of the low cost generation. That payment is appropriately not made to the low cost generation which is paid its LMP. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the current FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective. The FTR mechanism has become unduly complicated and has deviated significantly from its original purpose. Return of all the excess payments to load would result in a perfect hedge against congestion. The current FTR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has had to add increasingly complex rules and regularly intervene in the FTR mechanism because the PJM FTR design has moved further and further from these economic fundamentals. Some market participants have profited in various ways from these design flaws and those market participants now strongly defend the current design.

When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load, subject to transmission limits. This was true prior to the introduction of LMP markets and continues to be true in LMP markets.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the combined day-ahead and balancing (real-time) markets. FTRs permitted the loads, which pay for the transmission system, to continue to receive the benefits of access to either local or remote low cost generation by returning congestion to the load.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning of the FTR design that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. Prior to the introduction of LMP markets, payment for the delivery of low cost generation to load was based both on intrazonal generation and intrazonal transmission, both under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. But most load was served by intrazonal generation. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. There was no congestion revenue because customers paid only the actual cost of the low cost generation. The flawed idea that congestion is based on contract paths was inconsistent with the most basic logic of LMP and the resultant fissure has continued to widen. The origin of FTRs was the recognition that the way to hold load harmless from making the excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load. The result of the current FTR mechanism is a significant reduction in the value of FTRs as a hedge for load.

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP, but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants a hedge, it may enter into an arm's length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the purpose of FTRs.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs were the mechanism selected in PJM to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.[2] The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion must be defined correctly based on the operation of the network and not on arbitrary contract paths.

Effective April 1, 1999, when FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing (real-time) congestion to load. Congestion, in PJM's two settlement market, is the sum of day ahead and balancing congestion. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR design, the load still owns the rights to congestion revenue, but the ARR design allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR design, the right to all congestion revenues should belong to load. All congestion surplus should be assigned to load. But the actual implementation produces a very different result.

ARRs were an add on concept, defined based on a misunderstanding of FTRs, which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. ARRs used assumed contract paths to assign congestion to load. The use of contract paths for ARRs was a more critical mistake than using contract paths for FTRs because contract paths did not and do not account for all congestion. The use of contract paths led to the mistaken conclusion that some congestion did not belong to load and could be sold to FTR buyers. The ARR concept, as it is currently implemented, does not allow the FTR sellers, load, to establish a price at which they are willing to sell, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. Sellers are required to return some of the cleared auction revenue to FTR buyers when FTR payments are less than target allocations. So called surplus revenue is paid to FTR holders to ensure payment, despite the fact that willing FTR buyers paid the revenues in the auction for the rights to an uncertain level of congestion.

The use of generation to load contract paths, rather than the direct calculation of congestion, led to an increased divergence between FTR target allocations on the generation to load contract paths and actual total congestion. This divergence between actual network use and historic contract paths was exacerbated as new zones were added with their own historic generation to load contract paths and as significant numbers of

2 See *id.* at 62, 259–62,260 & n. 123.

generating units retired and new units were added.[3] Rather than understanding that the divergence resulted from the fact that a contract path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined contract paths was returned to load, regardless of its source. There is no such thing as excess congestion. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on a contract path fiction undermined the assignment of all congestion rights to load.

The contract path fiction is also the source of the incorrect definition of the product that is bought and sold as FTRs, the available supply of the product and the price paid to the buyers of the product. The product is defined as the difference in congestion prices across specific transmission contract paths. The difference in congestion prices across contract paths is not congestion and is not equal to congestion revenues. The quantity of the product made available for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. This fundamental confusion in the design of the market is the source of so called revenue shortfalls, of the redesign of the market to exclude balancing congestion, and of the need for PJM to intervene in the market. PJM has had to regularly intervene in the market because the market as designed cannot reach equilibrium based on the economic fundamentals. The product, the quantity of the product, and the price of the product are all incorrectly defined.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load, as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the fact that ARR holders cannot set the sale price for congestion revenue rights, the return of market revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The cumulative offset by ARRs for the 2011/2012 planning period through the first seven months of the 2021/2022 planning period, using the rules effective for each planning period, was 72.2 percent. Load has been underpaid by $2.7 billion from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design had not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. The design should simply have provided

3 For a comprehensive report on capacity retirements and capacity additions in PJM, see: "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022," (September 15, 2020) available at <http://www.monitoringanalytics.com/reports/Reports/2020/Constraint_Based_Congestion_Calculations_20200722.pdf>.

for the return of all congestion revenues to load. The design should have also provided for the ability of load to sell the rights to congestion revenue. That sale could be organized as an FTR auction with the product and the price clearly defined. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

The *2021 State of the Market Report for PJM* focuses on the 2020/2021 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2021, through December 31, 2021.

Table 13-1 The FTR/ARR markets results were partially competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Partially Competitive	
Market Performance	Partially Competitive	Flawed

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2021/2024 Long Term FTR Auction, the 2021/2022 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 2020/2021 Annual FTR Auction. Ownership of FTRs is disproportionately (76.2 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs are not permitted to participate in the market clearing.
- Market performance was evaluated as partially competitive because of the flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that sellers are required to return some of the cleared auction revenue to FTR buyers when FTR profits are not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Overview

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2021/2022 planning period ARRs were allocated to 1,459 individual participants, held by 131 parent companies. ARR ownership for the 2021/2022 planning period was unconcentrated with an HHI of 700.

Market Behavior

- **Self Scheduled FTRs.** For the 2021/2022 planning period, 26.1 percent of eligible ARRs were self scheduled as FTRs.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first seven months of the 2021/2022 planning period, ARRs offset only 44.8 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $2.7 billion from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period. The cumulative offset for that period was 72.2 percent of total congestion.
- **ARR Payments.** For the first seven months of the 2021/2022 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $626.8 million, while PJM collected $803.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2020/2021 planning period, the ARR target allocations were $517.1 million while PJM collected $691.2 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.
- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first seven months of the 2021/2022 planning period, PJM allocated a total of 18,624.9 MW of residual ARRs with a total target allocation of $11.4 million, up from 13,601.8 MW, with a total target allocation of $5.7 million, in the first seven months of the 2020/2021 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 29,776 MW of ARRs associated with $426,700 of revenue that were reassigned in the 2020/2021 planning period. There were 23,868 MW of ARRs associated with $434,400 of revenue that were reassigned for the first seven months of the 2021/2022 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions was changed effective with the 2020/2021 planning period. The new design includes auctions for each remaining month in the planning period. The prior design included auctions for the next three individual months plus remaining quarters.

Market Structure

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 83.2 percent of prevailing flow and 92.7 percent of counter flow FTRs for January through December, 2021. Financial entities owned 76.4 percent of all prevailing and counter flow FTRs, including 68.2 percent of all prevailing flow FTRs and 86.4 percent of all counter flow FTRs during the period from January through December 2021. Self scheduled FTRs account for 5.0 percent of all FTRs held.
- **Market Concentration.** For prevailing flow obligation FTRs in the Monthly Balance of Planning Period Auctions for the first seven months of the 2021/2022 planning period, ownership of cleared prevailing flow bids was unconcentrated in all of the periods. Ownership of cleared counter flow bids was unconcentrated in 74.6 percent of periods and moderately concentrated in 25.4 percent of periods, in the first seven months of the 2021/2022 planning period.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2021/2022 planning period, total participant FTR sell offers were 12,374,729 MW.
- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2021/2022 planning were 22,708,418 MW.

- **FTR Forfeitures.** Total FTR forfeitures were $4.6 million for the 2020/2021 planning period. On May 20, 2021, FERC issued an order ruling the $0.01 definition of an increase in the value of an FTR unjust and unreasonable, but upheld the other parts of PJM's forfeiture rule, and required PJM to modify the rule. FERC did not rule on PJM's compliance filing. As a result, there was no FTR forfeiture rule in place from May 20, 2021 through the end of 2021.
- **Credit.** There were 10 collateral defaults in 2021. There were 10 payment defaults not involving GreenHat Energy, LLC for a total of $2.3 million. GreenHat Energy's default payments ended with the 2020/2021 planning period for a total of $179.5 million. Of the 20 defaults, 15 were promptly cured, and the remainder are awaiting resolution.

Market Performance

- **Quantity.** In the first seven months of the 2021/2022 planning period, Monthly Balance of Planning Period FTR Auctions cleared 4,324,179 (19.0 percent) of FTR buy bids and 2,463,546 MW (19.9 percent) of FTR sell offers. For the 2020/2021 planning period, Monthly Balance of Planning Period FTR Auctions cleared 2,720,662 (17.1 percent) of FTR buy bids and 2,770,301 MW (16.2 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods of the first seven months of the 2021/2022 planning period was $0.20 per MWh.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $41.6 million in the first seven months of the 2021/2022 planning period, up from $31.6 million for the same time period in the 2020/2021 planning period.
- **Revenue Adequacy.** The first seven months of the 2021/2022 planning period were revenue inadequate. FTRs were paid 91.1 percent of the target allocations for the first seven months of the 2021/2022 planning period, including distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. In the first seven months of the 2021/2022 planning period, physical entities received $118.6 million in profits on FTRs purchased directly (not self scheduled), up from $39.1 million profits in the same time period in the 2020/2021 planning period and financial entities received $252.6 million in profits, up from $141.3 million profits in the same time period in the 2020/2021 planning period.

Markets Timeline

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Table 13-2 shows the date of first availability and final closing date for all annual ARR and FTR products.

Table 13-2 Annual FTR product dates

Auction	Initial Open Date	Final Close Date
2021/2025 Long Term	6/1/2021	3/3/2022
2021/2022 ARR	3/1/2021	3/30/2021
2021/2022 Annual	4/6/2021	4/29/2021

Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long

Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[4] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order

4 See "PJM Manual 6: Financial Transmission Rights," Rev. 27 (Aug. 25, 2021).

to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. New recommendation. Status: Not adopted.)

Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by load of their congestion revenue rights.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives including so called revenue adequacy. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[5] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[6] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that congestion is defined, in

5 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
6 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

A subsequent rule change was implemented that modified the allocation of surplus auction revenue to load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[7] ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. While this rule change increased the level of congestion revenues returned to load, the rules do not recognize ARR holders' rights to all congestion revenue. With this rule in effect for the first seven months of the 2021/2022 planning period, ARRs and FTRs offset 44.8 percent of total congestion. Load has been underpaid congestion revenues by $2.7 billion from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period. The cumulative offset for that period was 72.2 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs are entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

In response to a consultant's recommendations, PJM has proposed to increase Stage 1A ARR allocations to 60 percent of Network Service Peak Load (NSPL) ("Stage 1A Proposal").[8] [9] While PJM's proposal will increase Stage 1A rights, this will come at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's proposal will not improve the alignment of congestion property rights to load, but will exacerbate the current misalignment.

Under the current rules, Stage 1A allocations are limited to 50 percent of Network Service Base Load. In the 2021/2022 planning period there were infeasibilities on 53 internal PJM constraints totaling 5,881 MW. These MW already result in revenue inadequacy because they are physically infeasible, but must be granted under the rules. In order to grant infeasible Stage 1A ARR allocations, PJM artificially increases the capacity of the constraint, which results in the over allocation issues of FTRs in the FTR auction. Increasing the amount of Stage 1 ARR allocations will exacerbate this issue and result in higher revenue inadequacy.

PJM's proposal is not internally consistent and does not follow its own logic. PJM's proposal does not extend the proposed changes beyond year one in the long term auction. The result is that buyers of long term FTRs can continue to purchase and hold capacity on the system before ARRs even have access to it. This increases over allocations and reduces load's access to ARRs.

7 163 FERC ¶61,165 (2018).

8 *See* "Review of PJM's Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTRs)," London Economics, December 16, 202.

9 *See* "Auction Revenue Rights and Financial Transmission Rights Tariff and Operating Agreement Revisions," Docket No. ER22-000, January 10, 2022.

PJM continues to fail to recognize the actual underlying issue. The only effective way to address the underlying issue identified by PJM's consultant, the fact that load does not actually get the rights to all congestion, is to modify the market design to assign congestion revenue rights to load.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the network congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy, and generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that will be credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with auction clearing price for the 50 percent of CRR that was sold to the third party. Depending on actual congestion, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.

Auction Revenue Rights

Auction Revenue Rights (ARRs) are the mechanism used to assign congestion rights to load, using an archaic contract path based approach, and sell those rights to FTR buyers in various auctions. ARR values are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction. ARR sellers have no opportunity to define a price at which they are willing to sell and must accept the prices as defined by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. But some auction revenues may be returned to FTR buyers, despite the fact that FTR buyers willingly paid a defined price for FTRs. PJM has significant discretion over the level of supply made available to FTR buyers. The appropriate goals of that discretion should be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 24 hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between the ARR sink and source from the Annual FTR Auction.[10] ARR target allocations are a set value at the time of the Annual FTR Auction. It is logically possible for ARRs to be revenue inadequate if the money collected from the FTR auction is not enough to pay the entirety of ARR target allocations for the planning period. This is extremely unlikely and can only happen if there is a modeling difference between the system model used for ARRs and the system model used for FTRs and the FTR MW are reduced. An ARR's target allocation, or value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all congestion revenues. In the current design, all auction revenues should be paid to ARR holders.

The quantity of the product made available as ARRs or for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of the concept of system capability in assigning ARRs is derived entirely from the contract path approach used in the PJM design. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. In the current approach, system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model.

Market Design

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone. For the 2006/2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DUQ and DOM Control Zones. For the 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Each March, PJM allocates annual ARRs to eligible customers in a three stage process: Stage 1A, Stage 1B and Stage 2B. Stage 1A ARRs are assigned based on historic contract paths and Stage 1A ARRs must be preserved for at least ten planning periods regardless of system or regulatory changes.[11]

In Stage 1A, LSEs can obtain ARRs, based on their lowest daily peak load in the prior twelve month period, and based on generation to load contract paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired and PJM has replaced it. The historical reference year is the year in which PJM markets were implemented, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs, up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the

10 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints.

11 See "PJM Manual 6: Financial Transmission Rights," Rev. 28 (Dec. 15, 2021) at 23.

historical reference year, subject to a cap of lowest daily peak load in the prior year. Network service customers can obtain Stage 1A ARRs based on the MW of firm service provided during the reference year, subject to a cap of lowest daily peak load in the prior year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[12]

In Stage 1B, network transmission service customers can obtain ARRs based on their share of zonal peak load, based on generation to load contract paths, up to the difference between their share of zonal peak load and Stage 1A allocations. Firm, point to point transmission service customers can obtain ARRs based on the MW of long-term, firm, point to point service provided between the receipt and delivery points for the historical reference year.

In Stage 2, network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone up to their total peak network load in that zone. Firm, point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

When ARR holders self schedule FTRs, the ARR holders choose to be paid based on variable target allocations rather than the fixed ARR value determined in the annual FTR auction. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[13] ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction.

Effective for the 2015/2016 planning period, when residual zonal pricing was introduced, ARRs default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[14]

In 2016, FERC ordered PJM to remove retired resources from the generation to load contract paths used to allocate Stage 1A ARRs.[15] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[16] Existing Stage 1A resources retain their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load contract paths should not be used as a basis for assigning the rights to congestion revenue. Contract paths are not an accurate representation of the reasons that congestion revenues are paid or of how load is served in a network and will, by definition, not accurately measure the exposure of load to congestion.

Market Structure

ARRs are allocated on an annual basis. For the 2021/2022 planning period there were 1,459 individual participants, held by 131 parent companies.

The ownership of ARRs was unconcentrated, with an HHI of 851, for the 2020/2021 planning period.

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a year, but guaranteed for 10 years, with the ability for a participant to opt out of any planning period within the 10 years. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process. But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract

12 See "PJM Manual 6: Financial Transmission Rights," Rev 28 (Dec. 15, 2021).
13 OATT Attachment K 7.1.1.(b).
14 See "PJM Manual 6: Financial Transmission Rights," Rev. 28 (Dec. 15, 2021) at 35.
15 156 FERC ¶ 61,180 (2016).
16 See FERC Docket No. EL16-6-003.

paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, an LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs and residual ARRs within the control zone based on the shifted load.[17] ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. The reassignment of positively valued ARRs supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 29,776 MW of ARRs associated with $426,700 of revenue that were reassigned for the 2020/2021 planning period. There were 23,868 MW of ARRs associated with $434,400 of revenue that were reassigned in the first seven months of the 2021/2022 planning period.

Table 13-3 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2020 and September 2021.

Table 13-3 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2020 through December 2021

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2020/2021 (12 months)	2021/2022 (7 months)	2020/2021 (12 months)	2021/2022 (7 months)
ACEC	417	201	$2.9	$1.0
AEP	2,613	3,329	$25.2	$28.2
APS	1,386	824	$20.8	$8.2
ATSI	3,012	2,281	$25.5	$23.8
BGE	2,419	1,728	$151.1	$187.6
COMED	2,588	2,118	$16.8	$14.6
DAY	687	877	$5.1	$3.6
DUKE	827	885	$26.2	$34.3
DUQ	1,526	1,348	$6.7	$6.1
DOM	431	64	$4.4	$1.1
DPL	736	544	$21.7	$30.4
EKPC	0	0	$0.0	$0.0
JCPLC	927	734	$4.3	$1.5
MEC	608	755	$2.9	$3.8
OVEC	0	0	$0.0	$0.0
PECO	3,605	2,715	$24.7	$7.8
PE	603	544	$7.3	$5.3
PEPCO	2,176	1,349	$27.3	$23.5
PPL	3,358	2,870	$38.5	$44.4
PSEG	1,506	682	$15.3	$8.8
REC	352	20	$0.1	$0.0
Total	29,776	23,868	$426.7	$434.4

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs can only be allocated to participants whose ARRs were prorated in Stage 1B and only to a maximum of the prorated reduction, so not all available Residual ARRs are allocated. Residual ARRs are automatically assigned to eligible participants the month before the effective date, are effective for a single month and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations in the relevant monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not

17 See "PJM Manual 6: Financial Transmission Rights," Rev. 28 (Dec. 15, 2021).

assigned to participants.[18] In prior planning periods, PJM's modeling of excess outages in order to manage FTR market outcomes resulted in the allocation of some ARRs that would have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-4 shows the Residual ARRs allocated to participants and the associated target allocations. The available volume is the total additional capacity available to be allocated as Residual ARRs. The cleared volume is the residual ARR capacity actually allocated to participants with prorated ARRs based on the level of prorated ARRs in Stage 1B and the affected paths. In the first seven months of the 2021/2022 planning period, PJM allocated a total of 18,624.9 MW of Residual ARRs with a target allocation of $11.4 million. In the same time period for the 2020/2021 planning period, PJM allocated a total of 13,601.8 MW of residual ARRs with a target allocation of $5.7 million.

Table 13-4 Residual ARR allocation volume and target allocation: 2014/2015 planning period through 2021/2022 planning period

Planning Period	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
2014/2015	65,095.3	22,532.9	34.6%	$8,160,918.27
2015/2016	61,807.0	37,042.4	59.9%	$8,620,353.27
2016/2017	71,000.7	35,034.9	49.3%	$6,986,723.44
2017/2018	81,040.8	39,597.4	48.9%	$17,497,625.78
2018/2019	49,646.9	27,335.6	55.1%	$11,817,002.00
2019/2020	48,286.5	27,233.2	56.4%	$12,369,580.58
2020/2021	43,484.2	25,028.0	57.6%	$11,677,033.36
2021/2022	28,819.1	18,624.9	64.6%	$11,420,537.73

* First seven months of 2021/2022 planning period

IARRs

In theory, Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to result in IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[19]

There are three sources of IARRs: IARRs based on a specific transmission investment; IARRs based on merchant transmission or generation interconnection projects; and IARRs based on RTEP upgrades. In the case of a specific transmission investment, the participant elects desired IARR MW between a specified source and sink and PJM and the affected transmission owners determine the upgrades necessary to create incremental capability.[20] In the other two cases, the participants paying for the upgrades are assigned IARRs if any are created. There have been 13 successful IARR requests totaling 2,990.1 MW. One IARR path of 64.5 MW was terminated (June 1, 2012), leaving 12 unique source and sink combinations of 2,925.6 MW of IARRs. Of these 12 unique paths, three paths consisting of 1,200.0 MW were based on specific transmission investments requests, six paths consisting of 1,047.4 MW were based on merchant transmission requests and three paths consisting of 678.6 MW were based on customer funded (RTEP) transmission projects. The three paths based on specific transmission investments involved a generation company working with its affiliated transmission company. The other nine paths were based on projects that would have been built regardless of the addition of IARRs.

The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Maintaining the IARR process impedes the search for real solutions. PJM's process for creating and assigning IARRs is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[21]

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions be available upon request to the party that pays for such upgrades or expansions.[22] Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights, which are given first and absolute priority in PJM's annual allocation process. Granting Stage

18 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

19 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.

20 See Attachment EE of the PJM Open Access Transmission Tariff <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>.

21 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").

22 *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶61,077 (2006) ("Order No. 681"), order on reh'g, Order No. 618-A, 117 FERC ¶ 61,201 (2006), *order on reh'g*, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. If the annual market model used to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

The MMU recommends that IARRs be eliminated from the PJM tariff. If IARRs are not eliminated, the MMU recommends that IARRs be subject to prorating like all other ARR rights rather than being exempt from prorating.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the day-ahead energy market across specific FTR transmission paths. These day-ahead congestion price differences, multiplied by the FTR position in MW, are termed the FTR target allocations. The FTR target allocations define the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to make payments rather than receive revenues in the FTR market. One of the fundamental flaws in the FTR design is the mismatch between congestion and the differences in day-ahead prices between nodes. The difference in day-ahead congestion prices is not congestion. Target allocations are not congestion.

Under the current rules, the revenue available to pay FTR holders' target allocations in a given month includes day-ahead congestion, payments by holders of negatively valued FTRs, auction revenues greater than ARR target allocations, and any charges made to day-ahead operating reserves which occur where there are hours with net negative congestion. Any such revenue above FTR target allocations from prior months in a planning period are used to pay any current month shortfalls. Target allocations are a cap on payments to FTR holders for each planning period. At the end of each planning period, any surplus revenue above the target allocations is distributed to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. For example, if the payout ratio is less than 1.0 at the end of the planning period, the payments to all FTRs are reduced. Payments are made pro rata based on target allocations. The result is widespread cross subsidies because assignment of path specific FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning period.

Auction market participants may offer to buy FTRs between any eligible pricing nodes on the system, as defined by PJM for each auction. For the Annual FTR Auction and FTRs bought in the monthly auctions, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. For the Long Term FTR Auction there is a more restricted set of available hubs, control zones, aggregates, generator buses and interface pricing points available. PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW.

FTRs are bought from supply defined by PJM. The fact that load is selling congestion revenue rights is not fully recognized in the FTR design, although FTR buyers can resell FTRs at a price they agree to accept. Load has no role in defining the price at which PJM sells FTRs on their behalf. PJM's objective in the auctions is to maximize auction revenue, given the total set of bid prices and bid MW, but absent reservation prices from load. The failure to allow sellers the ability to decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction revenue and that the FTR market is not really a market.

Once bought from PJM, FTRs can be bought and sold. Buy bids are bids to buy FTRs in the auctions. Sell offers are offers to sell existing FTRs in the auctions.

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is no requirement to report bilateral transactions, or any information about them, to PJM.

Supply and Demand

Total FTR supply in each auction is limited by the definition of the transmission system capacity included in the PJM FTR market model as modified, for example, by PJM assumptions about transmission outages, for which there are no clear rules. PJM may also limit available transmission capacity through subjective judgment exercised without any clear guidelines.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

The FTR auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages.[23] In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model will generally have significant distributional consequences; they will affect different areas very differently. The fact that outages are modeled at significantly lower than historical levels results in selling too much FTR capacity, which creates downward pressure on ARR prices. To address this issue, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual expected transmission capacity.

Long Term FTR Auctions

In July 2006, FERC approved Order No. 681 mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets. FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights."[24] Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design. Excess system capability in years two and three of the long term FTR auction is never made available to load in the form of ARRs and is only made available to FTR buyers.

PJM conducts the Long Term FTR Auction for the next three consecutive planning periods. The Long Term FTR Auction consists of five rounds beginning in June of the preceding planning period and continuing through March. FTRs purchased in prior rounds or Long Term Auctions may be offered for sale in subsequent rounds of the long term, annual or monthly FTR auctions. FTRs obtained in the Long Term FTR Auctions have terms of one year. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations, with FTR options unavailable in the Long Term FTR Auctions.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and uses

23 See the *2019 State of the Market Report for PJM*, Volume II, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.

24 Order No. 681 at P 17.

the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The ARR requests are greater than the previously cleared ARRs. The difference between the requested ARRs and the ARR/FTR market model's transmission system capacity, both without outages, determines the residual capability offered in the Long Term FTR Auction. The revisions provide ARR holders with more congestion rights in the Long Term FTR Auction that will carry into the Annual FTR Auction.

But the revisions do not address the congestion revenue rights sold in years two and three of the Long Term FTR Auction, which remain unavailable to ARRs. Capacity awarded in the Long Term FTR Auction is unavailable as ARRs in years two and three. As a result, the rights to significant congestion revenues are still assigned to the Long Term FTR Auction without ever having been made available to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design which is to return all congestion revenues to load.

Long Term FTR Auction transmission capacity is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction capability. Even this approach does not, and cannot, preserve all possible capacity for ARR holders in the first year of the Long Term Auction due to changes in system topology and outage selection between planning periods. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction.

Annual FTR Auctions

Annual FTRs are effective for an entire planning period, June 1 through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM decides would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[25] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear, is not defined and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. The Annual FTR Auction consists of four rounds that allow any PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24 hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Monthly Balance of Planning Period FTR Auctions

Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Before the 2020/2021 planning period, the first three individual months, and quarterly periods that had not yet begun, were available for bid or offer. Beginning with the 2020/2021 planning period, market participants can bid for or offer monthly FTRs for any of the remaining individual calendar months in the planning period. FTRs in the auctions include obligations and options and 24 hour, on peak and off peak products.[26]

Bilateral Market

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is currently no requirement to report bilateral transactions, or any information about them, to PJM. Bilateral transactions that are not done through

25 See "PJM Manual 6: Financial Transmission Rights," Rev. 28 (Dec. 15, 2021).

26 See "PJM Manual 6: Financial Transmission Rights," Rev. 28 (Dec. 15, 2021).

PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Bilateral transactions not reported to PJM are dependent on the contract established between the parties.

For bilateral trades reported to PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. Bilateral FTRs reported to PJM can also include more restrictive start and end times, meaning that the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

FTR Bid Limits

PJM has the authority to limit participant's bids to 5,000 to avoid or mitigate significant system performance problems related to bid/offer volume.[27] PJM has had a cap of 10,000 bids and offers per auction round and per period at the corporate family level for more than a year, although the rule has not been enforced. On December 11, 2019, PJM made an informational announcement to urge participants to respect the rule.[28] Some participants continued to exceed the limit in 2020 through the use of multiple affiliates, although the number of such participants was significantly reduced. On October 26, 2020, the MMU informed stakeholders that it had notified companies that violated the limits persistently that the companies should comply, and recommended that PJM enforce the limit.[29] On November 5, 2020, PJM proposed to add a language in PJM Manual 6 regarding the bid limit.[30] The MMU recommends that PJM enforce the FTR auction bid limits at the corporate family level starting immediately.

Market Structure

In order to evaluate the ownership of FTRs, the MMU categorizes all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks, trading firms and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-5 presents the monthly balance of planning period FTR auction cleared FTRs for 2021 by trade type, organization type and FTR direction. Financial entities purchased 83.2 percent of prevailing flow FTRs, down 2.8 percentage points, and 92.7 percent of counter flow FTRs, up 3.8 percentage points, from 2020, with the result that financial entities purchased 87.7 percent, up 0.3 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction for 2021.

Table 13-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through December, 2021

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	16.8%	7.3%	12.3%
	Financial	83.2%	92.7%	87.7%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	5.3%	3.2%	4.7%
	Financial	94.7%	96.8%	95.3%
	Total	100.0%	100.0%	100.0%

Table 13-6 shows the monthly cumulative HHI values for cleared obligation MW for the first seven months of the 2021/2022 planning period monthly auctions for prevailing flow FTRs. Ownership of cleared prevailing flow bids was unconcentrated in all of the periods.[31]

27 Operating Agreement Schedule 1 § 7.3.5(d) allows PJM to limit participant's bids to 5,000 to avoid or mitigate significant system performance problems related to bid/offer volume.

28 *See* "Informational Update: FTR Auction Bid Limits," PJM Presentation to the Market Implementation Committee (December 11, 2019) <https://www.pjm.com/-/media/committees-groups/committees/mic/20191211/20191211-item-06-ftr-auction-bid-limits.ashx>.

29 *See* "Market Monitor Report," IMM Presentation to the Members Committee (October 26, 2020) <https://www.pjm.com/-/media/committees-groups/committees/mc/2020/20201026-webinar/20201026-item-07-imm-report.ashx>.

30 *See* "Manual 6, Rev. 26: FTR Auction Bid Limits," PJM Presentation to the Market Implementation Committee (November 5, 2020) <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201105/20201105-item-05a-m6-updates-ftr-bid-limits.ashx>.

31 *See 2021 State of the Market Report for PJM*, Section 3: Energy Market, Competitive Assessment for HHI definitions.

Table 13-6 Monthly Balance of Planning Period FTR Auction HHIs by period for prevailing flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-21	445	627	649	568	614	624	631	542	622	758	831	854
Jul-21		387	510	489	503	533	543	520	568	620	697	680
Aug-21			331	443	486	534	534	528	583	603	691	678
Sep-21				432	466	515	521	529	579	595	709	687
Oct-21					426	491	511	519	565	580	686	672
Nov-21						431	489	508	548	563	653	654
Dec-21							419	474	498	546	628	625

Table 13-7 shows the monthly cumulative HHI values for cleared obligation MW for the first seven months of the 2021/2022 planning period monthly auctions by month for counter flow FTRs. Ownership of cleared counter flow bids was unconcentrated in 74.6 percent of periods and moderately concentrated in 25.4 percent of periods, in the first seven months of the 2021/2022 planning period.

Table 13-7 Monthly Balance of Planning Period FTR Auction HHIs by period for counter flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-21	679	775	815	1086	1070	1153	1170	1155	1088	1263	1312	1357
Jul-21		609	617	754	821	899	911	892	857	934	1026	1028
Aug-21			554	685	738	853	886	869	863	948	1019	1018
Sep-21				935	693	796	851	830	830	964	1060	1025
Oct-21					649	713	800	772	776	908	1006	954
Nov-21						656	758	745	767	874	981	939
Dec-21							651	696	723	825	929	890

Table 13-8 shows the average daily FTR ownership for all FTRs for 2021 by organization type, by FTR direction and self scheduled FTRs.

Table 13-8 Daily FTR held position ownership by FTR direction: 2021

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	22.9%	13.4%	18.7%
Physical Self Scheduled	8.9%	0.1%	5.0%
Financial	68.2%	86.4%	76.4%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits in the FTR auction model. If, in PJM's judgment, the normal transmission limit is not consistent with revenue adequacy goals and simultaneous feasibility, then transmission limits are reduced pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[32] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow bids without being required to clear the corresponding prevailing flow bids.[33] The use of both of these procedures is contingent on the conditions that: PJM actions not affect the revenue adequacy of allocated ARRs; all requested self scheduled FTRs clear; and net FTR auction revenue is positive.

Monthly Balance of Planning Period Auctions

Table 13-9 provides the monthly balance of planning period FTR auction market volume for the entire 2020/2021 and the first seven months of the 2021/2022 planning periods. There were 18,588,476 MW of FTR obligation buy bids and 10,445,193 MW of FTR obligation sell offers for all bidding periods in the first seven months of the 2021/2022 planning period. The monthly balance of planning period FTR auction cleared 4,087,410 (22.0 percent) of FTR obligation buy bids and 2,048,561 MW (19.6 percent) of FTR obligation sell offers.

There were 4,119,942 MW of FTR option buy bids and 1,929,535 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2021/2022 planning period. The ownership of options was highly concentrated in all periods. The monthly auctions cleared 236,769 MW (5.7 percent) of FTR option buy bids and 414,985 MW (21.5 percent) of FTR option sell offers.

32 See "PJM Manual 6: Financial Transmission Rights," Rev. 28 (Dec. 15, 2021).
33 See *id.*

Table 13-9 Monthly Balance of Planning Period FTR Auction market volume: 2021

Monthly Auction	Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-21	Obligations	Buy bids	381,342	1,836,655	322,062	17.5%	1,514,593	82.5%
		Sell offers	217,469	811,662	130,359	16.1%	681,304	83.9%
	Options	Buy bids	6,018	442,023	14,751	3.3%	427,272	96.7%
		Sell offers	28,121	237,886	32,306	13.6%	205,581	86.4%
Feb-21	Obligations	Buy bids	376,380	1,790,943	392,484	21.9%	1,398,459	78.1%
		Sell offers	202,939	761,827	137,133	18.0%	624,694	82.0%
	Options	Buy bids	2,117	200,050	8,830	4.4%	191,221	95.6%
		Sell offers	20,855	207,239	30,062	14.5%	177,176	85.5%
Mar-21	Obligations	Buy bids	294,408	1,424,569	327,035	23.0%	1,097,534	77.0%
		Sell offers	150,359	603,193	126,499	21.0%	476,694	79.0%
	Options	Buy bids	1,593	102,266	5,694	5.6%	96,572	94.4%
		Sell offers	14,659	155,357	37,104	23.9%	118,253	76.1%
Apr-21	Obligations	Buy bids	232,361	1,038,292	235,418	22.7%	802,874	77.3%
		Sell offers	103,242	396,155	88,706	22.4%	307,449	77.6%
	Options	Buy bids	952	95,317	4,750	5.0%	90,567	95.0%
		Sell offers	8,212	100,079	33,112	33.1%	66,967	66.9%
May-21	Obligations	Buy bids	143,525	726,081	172,760	23.8%	553,321	76.2%
		Sell offers	45,385	177,164	47,835	27.0%	129,329	73.0%
	Options	Buy bids	476	6,658	1,963	29.5%	4,695	70.5%
		Sell offers	3,048	45,362	21,620	47.7%	23,742	52.3%
Jun-21	Obligations	Buy bids	712,198	3,587,115	684,374	19.1%	2,902,741	80.9%
		Sell offers	511,008	1,831,087	418,763	22.9%	1,412,324	77.1%
	Options	Buy bids	22,795	474,246	44,199	9.3%	430,046	90.7%
		Sell offers	58,595	409,723	86,979	21.2%	322,744	78.8%
Jul-21	Obligations	Buy bids	710,795	3,302,256	707,723	21.4%	2,594,533	78.6%
		Sell offers	539,136	1,840,759	416,775	22.6%	1,423,984	77.4%
	Options	Buy bids	26,472	933,569	45,229	4.8%	888,340	95.2%
		Sell offers	55,449	331,308	59,043	17.8%	272,266	82.2%
Aug-21	Obligations	Buy bids	681,084	3,016,805	642,224	21.3%	2,374,581	78.7%
		Sell offers	484,901	1,630,064	324,703	19.9%	1,305,360	80.1%
	Options	Buy bids	31,238	982,824	42,841	4.4%	939,983	95.6%
		Sell offers	45,509	285,096	54,253	19.0%	230,843	81.0%
Sep-21	Obligations	Buy bids	597,853	2,667,831	629,359	23.6%	2,038,471	76.4%
		Sell offers	379,939	1,384,965	230,764	16.7%	1,154,201	83.3%
	Options	Buy bids	16,107	616,878	25,679	4.2%	591,199	95.8%
		Sell offers	34,313	230,759	37,841	16.4%	192,918	83.6%
Oct-21	Obligations	Buy bids	566,884	2,269,682	580,466	25.6%	1,689,216	74.4%
		Sell offers	388,073	1,322,781	239,199	18.1%	1,083,582	81.9%
	Options	Buy bids	27,001	505,049	22,842	4.5%	482,207	95.5%
		Sell offers	40,572	263,125	59,517	22.6%	203,607	77.4%
Nov-21	Obligations	Buy bids	451,818	1,937,011	452,751	23.4%	1,484,261	76.6%
		Sell offers	339,135	1,316,774	234,274	17.8%	1,082,500	82.2%
	Options	Buy bids	20,158	382,647	43,461	11.4%	339,186	88.6%
		Sell offers	33,758	218,310	63,673	29.2%	154,637	70.8%
Dec-21	Obligations	Buy bids	444,419	1,807,777	390,513	21.6%	1,417,263	78.4%
		Sell offers	297,782	1,118,763	184,083	16.5%	934,680	83.5%
	Options	Buy bids	12,374	224,729	12,518	5.6%	212,211	94.4%
		Sell offers	29,110	191,215	53,679	28.1%	137,535	71.9%
2020/2021*	Obligations	Buy bids	6,378,593	29,351,515	5,374,799	18.3%	23,976,716	81.7%
		Sell offers	3,827,330	12,711,366	2,216,261	17.4%	10,495,105	82.6%
	Options	Buy bids	89,167	5,672,240	311,288	5.5%	5,360,952	94.5%
		Sell offers	516,603	3,515,054	554,040	15.8%	2,961,014	84.2%
2021/2022**	Obligations	Buy bids	4,165,051	18,588,476	4,087,410	22.0%	14,501,066	78.0%
		Sell offers	2,939,974	10,445,193	2,048,561	19.6%	8,396,633	80.4%
	Options	Buy bids	156,145	4,119,942	236,769	5.7%	3,883,174	94.3%
		Sell offers	297,306	1,929,535	414,985	21.5%	1,514,550	78.5%

* Shows 12 months for 2020/2021 ** Shows 7 months for 2021/2022

Figure 13-1 shows the bid volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The prompt month is the final month for which FTRs for a specific month are sold. For example, June is the prompt month for June FTRs sold in the June auction, which occurs in May. The bid volume for the non-prompt months is significantly lower than for the prompt months. On average, the non-prompt month bid volume is 44.5 percent of the prompt month bid volume.

Figure 13-1 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June 2021 through December 2021 Auction

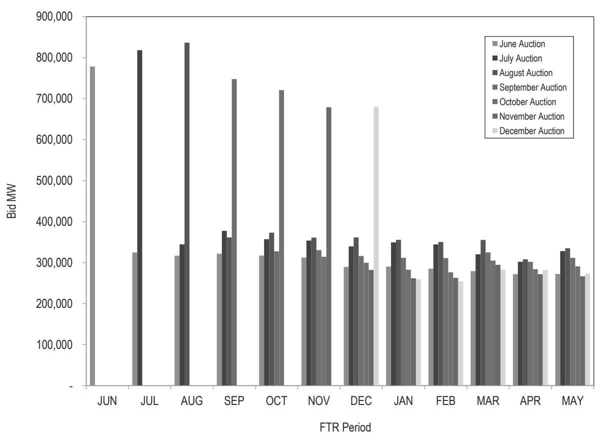
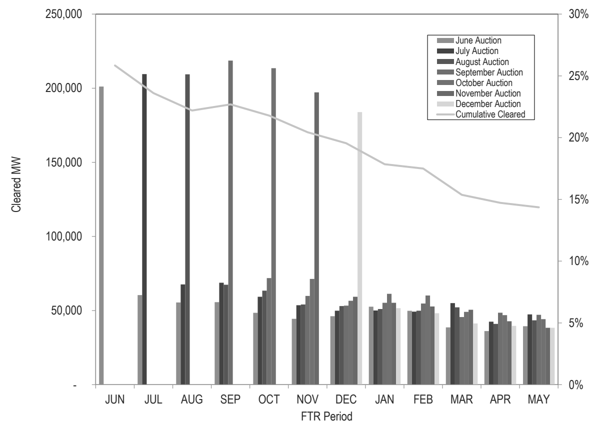


Figure 13-2 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt month cleared volume is 25.2 percent of the prompt month cleared volume.

Figure 13-2 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June 2021 through December 2021 Auction



Bilateral Market

Table 13-10 provides the PJM registered secondary bilateral FTR market volume for the 2020/2021 and the first seven months of the 2021/2022 planning periods. Bilateral FTR transactions registered through PJM do not need to include an accurate price or the entire volume of the transaction. Bilateral FTR transactions are not required to be registered through PJM. As a result, the bilateral data are not a reliable basis for evaluating actual bilateral activity in PJM FTRs.

Table 13-10 Secondary bilateral FTR market volume: 2020/2021 and 2021/2022[34]

Planning Period	Type	Class Type	Volume (MW)
2020/2021	Obligation	24-Hour	6,164.0
		On Peak	392.0
		Off Peak	96.0
		Total	6,652.0
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	0.0
		Total	0.0
2021/2022	Obligation	24-Hour	4,951.8
		On Peak	97,927.8
		Off Peak	67,980.8
		Total	170,860.4
	Option	24-Hour	0.0
		On Peak	16,009.0
		Off Peak	20,846.6
		Total	36,855.6

34 The 2020/2021 planning period covers bilateral FTRs that are effective for any time between June 1, 2020 through May 31, 2021, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 13-3 shows the FTR bid, net bid and cleared volume from June 2003 through December 2021 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. The cleared volume in August 2018 was negative due to the liquidation of the GreenHat FTR portfolio, which resulted in a large quantity of FTRs selling in the monthly auction.

Figure 13-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2021

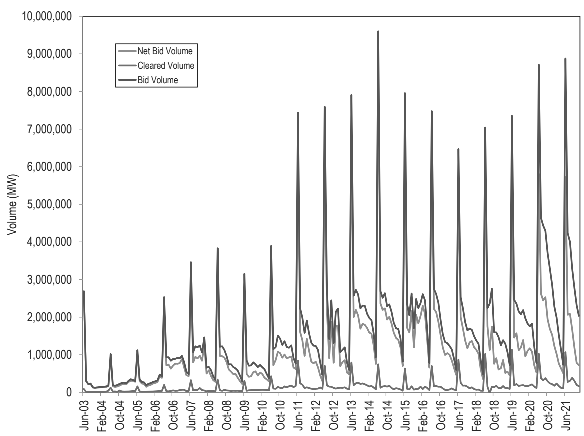
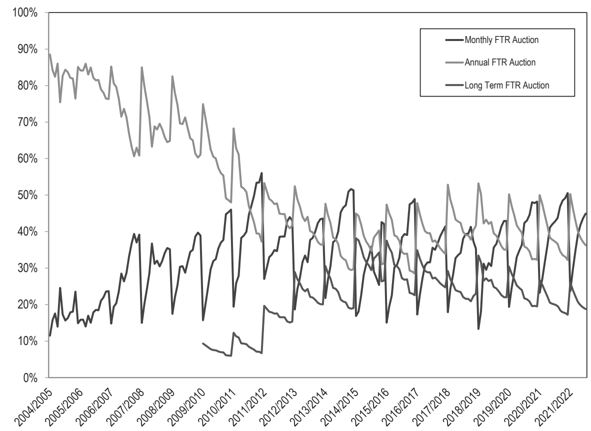


Figure 13-4 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through December 2021. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month in the relevant planning period. Over the course of each planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, resulting in a greater share of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in previous Monthly Balance of Planning Period Auctions, other than the current June auction, are no longer effective, resulting in a smaller share for monthly and a greater share for annual FTRs.

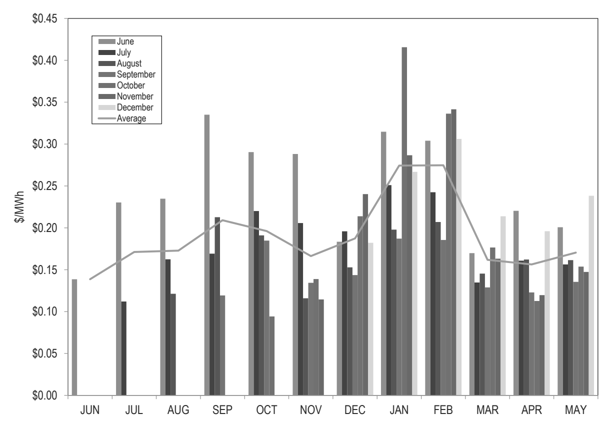
Figure 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2021



Price

Figure 13-5 shows the weighted average cleared buy bid price of obligations in the Monthly Balance of Planning Period FTR Auctions by bidding period for the first seven months of the 2021/2022 planning period and the average price per MWh for each of the FTR periods.

Figure 13-5 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy bid price per period (Dollars per MWh): 2021/2022 planning period



Profitability

FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. FTR profitability is relevant only to participants purchasing FTRs and is not relevant to self scheduled FTRs. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Profits include the payment of surplus to FTRs. Bilateral transactions are excluded from the profit calculations because there are inconsistent reporting requirements and no assurance that reported prices reflect the actual prices under the PJM rules. Bilateral profits and losses net to zero in market total profits and losses. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned the rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Profits in the first seven months in the 2021/2022 planning period include the auction cost and revenue from both buying and selling FTRs that were effective between June 2021 and December 2021. This includes FTRs from the 2019/2022, 2020/2023 and 2021/2024 Long Term auctions, the 2021/2022 Annual auction, and the Monthly auctions from June 2021 through December 2021. The costs and revenues of the yearly FTR products are prorated based on the time period of the FTRs. Any revenues or costs related to bilateral transactions are not included in profits.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR. The hourly revenues equal any positive hourly FTR target allocations, adjusted by the payout ratio plus any hourly auction revenues from the sale and/or the purchase of the FTR. The hourly auction costs equal any negative hourly FTR target allocations plus any hourly auction costs from the purchase and/or the sale of the FTR. The hourly auction costs and auction revenues are the product of the FTR MW and the auction price divided by the time period of the FTR in hours. The FTR revenues do not include after the fact adjustments which are very small and do not occur in every month.

The surplus includes surplus day-ahead congestion revenue and FTR auction surplus. The surplus is first allocated to FTR holders to cover any shortfall in paying FTR target allocations for the current month or prior months in the planning period. The end of planning period surplus or uplift was distributed to FTR holders prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, after covering any shortfall in FTR target allocations within the planning period, the net surplus at the end of the planning period is distributed to ARR holders. Profits include any surplus distribution or uplift payments that was used to satisfy any shortfall in FTR target allocations.

The fact that FTR profits in each planning period have been positive for financial entities as a group, regardless of the payout ratio, raises questions about the competitiveness of the market. FTR profits for financial entities were not positive in the 2019/2020 planning period when accounting for GreenHat losses but were positive otherwise. FTR profits for financial entities without GreenHat losses were positive in every planning period from 2012/2013 through 2021/2022 except the 2016/2017 planning period, and were positive if summed over the entire period (Table 13-13). It is not clear, in a competitive market, why FTR profits for financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed to zero.

Table 13-11 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction of the first seven months of the 2021/2022 planning period. All participants who were assigned ARRs are classified as physical ARR. Some participants that are not eligible for ARRs are classified as physical because they are physical participants, for example companies that own only generation.

In the first seven months of the 2021/2022 planning period, physical entities, including physical FTR and physical ARR participants, received $118.6 million in profits on FTRs purchased directly (not self scheduled), up from $39.1 million in the same time period in the 2020/2021 planning period. Financial participants received $252.6 million in profits, up from $141.3 million in the same time period in the 2020/2021 planning period. Self scheduled FTRs have zero cost.

ARR holders who self scheduled FTRs received $145.6 million in congestion revenues. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion and are not profits.

Table 13-11 FTR profits and revenues by organization type and FTR direction: 2021/2022: June through December

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$368,193,387	($115,621,164)	$252,572,223			
Physical	$140,109,205	($48,149,591)	$91,959,614			
Physical ARR	$47,118,705	($20,482,001)	$26,636,704	$147,661,864	($2,045,201)	$145,616,663
Total	$555,421,297	($184,252,755)	$371,168,541	$147,661,864	($2,045,201)	$145,616,663

Table 13-12 lists the monthly FTR profits for the 2020/2021 planning period and the first seven months of the 2021/2022 planning period by organization type. In the first seven months of the 2021/2022 planning period, profits for all participants were $371.2 million, up from $180.4 million in profits for the same time period in the 2020/2021 planning period. The largest month to month increase in profits was in November, $155.2 million. Among organization types, financial organizations had the largest increase in profits in the first seven months of the 2021/2022 planning period, $110.5 million, while physical ARR organizations' profits increased by $16.0 million.

Table 13-12 Monthly FTR profits by organization type: 2020/2021 and 2021/2022[35]

	Organization Type				
Month	Financial	Financial without GreenHat	Physical	Physical ARR	Total
Jun-20	$13,553,728	$14,169,535	$2,968,368	($105,462)	$16,416,634
Jul-20	$35,758,125	$35,699,812	$9,137,003	$3,750,023	$48,645,151
Aug-20	$26,341,215	$26,180,692	$6,690,519	$3,240,451	$36,272,185
Sep-20	$23,243,038	$22,978,996	$7,356,627	$4,494,466	$35,094,131
Oct-20	$9,270,440	$8,813,003	$5,358,560	($843,912)	$13,785,088
Nov-20	$7,462,052	$7,789,762	($3,735,384)	($2,396,979)	$1,329,689
Dec-20	$26,204,312	$26,414,749	$160,949	$2,536,264	$28,901,524
Jan-21	$14,413,025	$14,543,616	($606,901)	$1,014,141	$14,820,265
Feb-21	$26,325,929	$27,249,807	$14,548,075	$3,170,577	$44,044,582
Mar-21	$31,624,116	$31,679,111	$5,276,933	$5,960,090	$42,861,139
Apr-21	$33,914,216	$32,426,080	$6,217,364	$3,418,465	$43,550,045
May-21	$32,476,383	$32,960,851	$7,569,383	($5,256,074)	$34,789,692
Summary for Planning Period 2020/2021					
Total	$280,586,579	$280,906,014	$60,941,495	$18,982,052	$360,510,126
Jun-21	$15,067,557	$15,067,557	$7,186,702	($2,606,859)	$19,647,400
Jul-21	$5,372,702	$5,372,702	($609,812)	($3,039,244)	$1,723,646
Aug-21	$36,172,528	$36,172,528	$4,111,145	($2,200,327)	$38,083,347
Sep-21	$28,123,046	$28,123,046	$11,576,806	$728,730	$40,428,582
Oct-21	$23,827,339	$23,827,339	$20,344,006	$9,299,537	$53,470,882
Nov-21	$100,345,821	$100,345,821	$35,354,907	$20,803,798	$156,504,526
Dec-21	$43,663,229	$43,663,229	$13,995,860	$3,651,069	$61,310,159
Summary for Planning Period 2021/2022					
Total	$252,572,223	$252,572,223	$91,959,614	$26,636,704	$371,168,541

35 The GreenHat Default Allocation Assessment by PJM was finished by the 2020/2021 planning period and GreenHat had no remaining position starting in the 2021/2022 planning period.

Table 13-13 lists the historical profits by planning period by organization type beginning in the 2012/2013 planning period for purchased FTRs. (Profits do not include congestion revenue to self scheduled FTRs.) Surplus allocated to ARR holders in the 2018/2019 planning period was $112.3 million, $140.7 million in the 2019/2020 planning period, and $137.1 million in the 2020/2021 planning period.

Table 13-13 FTR profits by organization type: 2012/2013 through 2021/2022

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022
Financial	Profit	$201,825,234	$913,502,323	$250,551,943	$68,895,867	($12,525,947)	$239,981,474	$113,086,231	($21,139,644)	$280,586,579	$252,572,223
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918				
	Total	$151,520,826	$768,421,802	$270,005,781	$73,816,945	($3,715,680)	$330,343,392	$113,086,231	($21,139,644)	$280,586,579	$252,572,223
Financial without GreenHat	Profit	$201,825,234	$913,502,323	$250,551,785	$70,094,918	($11,821,248)	$240,111,850	$223,376,757	$25,150,852	$280,906,014	$252,572,223
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918				
	Total	$151,520,826	$768,421,802	$270,005,623	$75,015,995	($3,010,981)	$330,473,768	$223,376,757	$25,150,852	$280,906,014	$252,572,223
Physical	Profit	$68,537,800	$297,456,284	$82,853,390	$10,007,327	($4,010,669)	$57,532,872	($5,945,233)	($42,860,656)	$60,941,495	$91,959,614
	Surplus	($41,626,011)	($53,642,077)	$5,395,706	$1,865,146	$4,181,855	$34,296,618				
	Total	$26,911,789	$243,814,207	$88,249,096	$11,872,473	$171,186	$91,829,490	($5,945,233)	($42,860,656)	$60,941,495	$91,959,614
Physical ARR	Profit	$26,572,818	$366,128,947	$112,609,140	$82,181,795	($2,468,152)	$66,458,939	($6,248,557)	($49,614,191)	$18,982,052	$26,636,704
	Surplus	($25,873,836)	($81,279,067)	$18,515,990	$7,110,576	$12,040,688	$47,753,635				
	Surplus from Self scheduled FTRs	($45,978,766)	($81,765,964)	$15,530,158	$3,073,711	$6,469,297	$42,513,186				
	Total	$698,982	$284,849,881	$131,125,130	$89,292,371	$9,572,536	$114,212,574	($6,248,557)	($49,614,191)	$18,982,052	$26,636,704
Total		$179,131,597	$1,297,085,890	$489,380,007	$174,981,788	$6,028,043	$536,385,456	$100,892,442	($113,614,490)	$360,510,126	$371,168,541

* The first seven months of the 2021/2022 planning period

Table 13-14 shows the profits and losses of the five most and the five least profitable participants by patterns of ownership. Total MWh is the sum of all MWh by ownership type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by ownership type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top 5 participants by ownership type. The Top 5 Market Share of MWh is the sum of the MWh of the top 5 participants by ownership type divided by Total MWh. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by ownership type. The same logic applies for the statistics related to the Bottom 5 participants. The All row includes all participants including all ownership types when calculating the share of the profits and losses of the Top 5 and Bottom 5 participants. When all participants across ownership types are considered, three of the Top 5 participants and three of the Bottom 5 participants were financial participants. Of all the ownership types, the Top 5 physical ARR participants' share of profits was the highest, 96.1 percent, although the total profits of that group was the lowest. There are only a small number of physical ARR participants who directly purchase FTRs. The Bottom 5 physical participants' share of losses was the highest, 76.1 percent, although the difference with the other organization types' bottom 5 loss share is less than the difference in the top 5's profit share. When compared to the same time period in the 2020/2021 planning period, the sum of top 5 participants' profits increased by more than 100 percent for all ownership types. For the bottom 5 participants' losses, the sum of the financial and physical ARR participants' losses was similar to losses in the 2020/2021 planning period but the losses of the physical bottom 5 participants increased by more than 100 percent. There are participants who have had persistent losses for multiple years. It is possible for PJM FTR participants to have complementary positions in other trading platforms such as the Intercontinental Exchange (ICE) or Nodal Exchange.

Table 13-14 Top 5 and bottom 5 FTR profits by ownership type: 2021/2022: June through December

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	2,023,876,497	$166,688,845	$0.31	26.5%	54.5%	($38,432,047)	($0.14)	13.2%	71.8%
Physical	277,870,811	$70,295,479	$1.31	19.3%	56.5%	($24,658,055)	($0.59)	15.1%	76.1%
Physical ARR	209,793,031	$43,234,567	$0.48	42.7%	96.1%	($11,675,595)	($2.51)	2.2%	63.6%
All	2,511,540,339	$182,549,589	$0.34	21.1%	38.4%	($51,220,890)	($0.36)	5.7%	49.1%

Table 13-15 shows the shares of the number of profitable and unprofitable participants by ownership type weighted by FTR MWh in the first seven months of the 2021/2022 planning period. There were more profitable participants than unprofitable participants. By ownership type, financial and physical entities had more profitable participants than unprofitable participants but physical ARR entities had more unprofitable participants than profitable participants. Compared to the same period in the 2020/2021 planning period, the share of the unprofitable participants increased from 20.2 percent to 32.7 percent. The increase in the unprofitable physical ARR participants' share was the largest, from 35.3 percent to 55.1 percent. One of the reasons for the increased number of unprofitable participants is that those who bought counter flow FTRs had significant negative FTR target allocation relative to revenue from the auction (the price of the counterflow FTRs). The total profits and the profits by ownership type increased (Table 13-11), and top 5 profitable participants' profits more than doubled for all ownership types (Table 13-14). In other words, FTRs were more profitable in the 2021/2022 planning period to date, but for fewer participants. Profits were more concentrated in the first seven months of the 2021/2022 planning period than in the same period in the 2020/2021 planning period.

Table 13-15 Share of participants by profitability by ownership type: 2021/2022: June through December

Organization Type	Unprofitable	Profitable
Financial	29.7%	70.3%
Physical	37.2%	62.8%
Physical ARR	55.1%	44.9%
Total	32.7%	67.3%

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-16 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for 2021. The Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2021/2022 planning period netted $41.6 million in revenue, the difference between buyers paying $204.9 million and sellers receiving $263.3 million. For the entire 2020/2021 planning period, the Monthly Balance of Planning Period FTR Auctions netted $37.0 million in revenue with buyers paying $142.0 million and sellers receiving $105.0 million.

Table 13-16 Monthly Balance of Planning Period FTR Auction revenue: 2021

Monthly			Class Type			
Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-21	Obligations	Buy bids	$1,941,358	$3,115,732	$6,036,272	$11,093,362
		Sell offers	$118,732	$1,962,676	$4,515,876	$6,597,284
	Options	Buy bids	$7,201	$295,920	$368,044	$671,165
		Sell offers	$52,076	$1,307,888	$1,874,030	$3,233,994
Feb-21	Obligations	Buy bids	$1,488,611	$4,102,215	$8,421,228	$14,012,054
		Sell offers	$151,204	$3,430,637	$6,788,020	$10,369,861
	Options	Buy bids	$6,780	$178,510	$273,701	$458,991
		Sell offers	$66,074	$845,917	$1,324,871	$2,236,862
Mar-21	Obligations	Buy bids	$875,232	$4,248,129	$8,919,313	$14,042,674
		Sell offers	($370,674)	$2,359,553	$6,212,710	$8,201,589
	Options	Buy bids	$19,057	$213,699	$311,568	$544,324
		Sell offers	$52,023	$1,084,212	$1,726,196	$2,862,432
Apr-21	Obligations	Buy bids	$298,333	$3,124,790	$5,647,597	$9,070,720
		Sell offers	($41,738)	$1,795,035	$3,766,861	$5,520,159
	Options	Buy bids	$7,925	$94,663	$181,157	$283,745
		Sell offers	$28,839	$841,377	$1,210,681	$2,080,897
May-21	Obligations	Buy bids	$752,007	$1,524,128	$3,194,089	$5,470,225
		Sell offers	($71,677)	$1,089,999	$2,696,146	$3,714,468
	Options	Buy bids	$0	$139,731	$217,126	$356,857
		Sell offers	$593	$555,263	$831,306	$1,387,162
Jun-21	Obligations	Buy bids	$23,340,717	$9,404,124	$25,460,202	$58,205,042
		Sell offers	$945,610	$11,155,487	$25,557,332	$37,658,430
	Options	Buy bids	$497,178	$1,326,642	$1,779,074	$3,602,894
		Sell offers	$1,481,777	$2,870,409	$5,390,340	$9,742,526
Jul-21	Obligations	Buy bids	$15,661,148	$8,980,313	$20,009,562	$44,651,023
		Sell offers	$924,780	$9,727,764	$19,609,993	$30,262,536
	Options	Buy bids	$515,331	$1,087,379	$1,677,645	$3,280,356
		Sell offers	$1,335,702	$2,424,771	$4,041,930	$7,802,403
Aug-21	Obligations	Buy bids	$17,539,272	$5,131,710	$15,224,864	$37,895,846
		Sell offers	$1,340,545	$8,336,462	$17,598,418	$27,275,424
	Options	Buy bids	$344,696	$1,518,623	$2,265,025	$4,128,344
		Sell offers	$1,651,285	$2,217,229	$3,850,400	$7,718,915
Sep-21	Obligations	Buy bids	$13,948,629	$5,039,838	$14,673,250	$33,661,717
		Sell offers	$768,971	$6,378,411	$16,027,116	$23,174,497
	Options	Buy bids	$223,181	$847,307	$1,140,014	$2,210,502
		Sell offers	$1,444,340	$2,134,005	$3,803,811	$7,382,156
Oct-21	Obligations	Buy bids	$27,933,654	$2,832,919	$9,206,791	$39,973,364
		Sell offers	$1,810,365	$10,271,351	$18,503,339	$30,585,055
	Options	Buy bids	$281,517	$1,153,761	$2,139,020	$3,574,298
		Sell offers	$1,507,562	$4,232,969	$5,347,872	$11,088,403
Nov-21	Obligations	Buy bids	$10,501,911	$5,552,785	$14,278,621	$30,333,317
		Sell offers	$877,283	$7,193,512	$15,486,227	$23,557,022
	Options	Buy bids	$109,608	$2,539,925	$4,392,466	$7,042,000
		Sell offers	$2,523,463	$3,987,244	$5,982,489	$12,493,197
Dec-21	Obligations	Buy bids	$9,253,556	$6,866,991	$16,133,967	$32,254,514
		Sell offers	$2,075,232	$6,873,963	$13,802,932	$22,752,127
	Options	Buy bids	$293,333	$2,145,567	$1,609,095	$4,047,995
		Sell offers	$2,017,647	$4,116,563	$5,634,822	$11,769,032
2020/2021*	Obligations	Buy bids	$76,746,367	$23,793,302	$35,265,115	$135,804,784
		Sell offers	$2,204,711	$32,008,489	$44,772,400	$78,985,599
	Options	Buy bids	$105,703	$2,668,216	$3,395,976	$6,169,895
		Sell offers	$556,743	$11,393,636	$14,017,286	$25,967,665
	Net Total		$74,090,616	($16,940,607)	($20,128,594)	$37,021,415
2021/2022**	Obligations	Buy bids	$118,178,886	$43,808,681	$114,987,256	$276,974,824
		Sell offers	$8,742,786	$59,936,949	$126,585,356	$195,265,091
	Options	Buy bids	$2,264,845	$10,619,205	$15,002,338	$27,886,388
		Sell offers	$11,961,776	$21,983,190	$34,051,664	$67,996,631
	Net Total		$99,739,169	($27,492,253)	($30,647,426)	$41,599,490

* Shows twelve months for 2020/2021 **Shows seven months for 2021/2022

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-6 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first seven months of the 2021/2022 planning period. The top 10 sinks that produced financial benefit accounted for 37.3 percent of total positive target allocations with the Western Hub accounting for 12.0 percent of all positive target allocations. The top 10 sinks that created liability accounted for 25.7 percent of total negative target allocations with PSEG accounting for 8.5 percent of all negative target allocations.

Figure 13-6 Ten largest positive and negative FTR target allocations summed by sink: 2021/2022

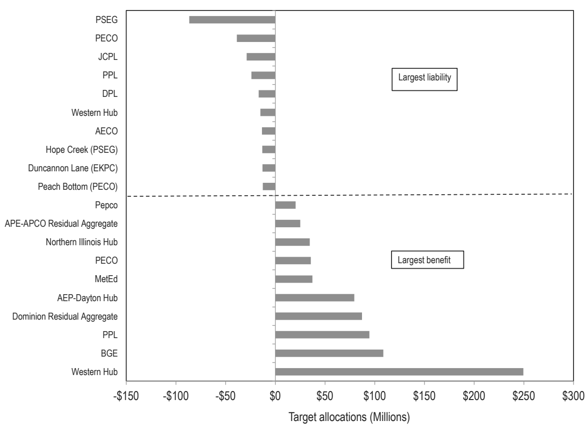
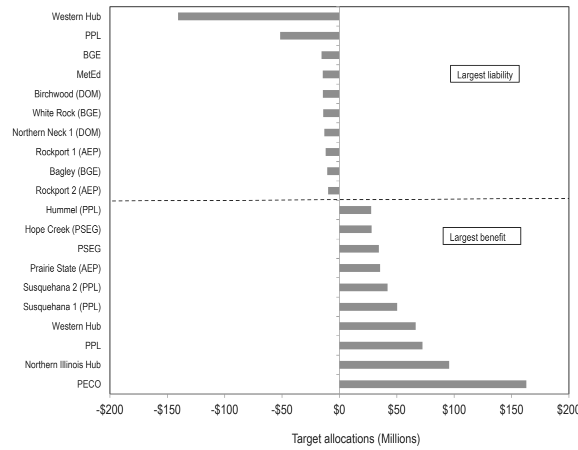


Figure 13-7 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first seven months of the 2021/2022 planning period. The top 10 sources with a positive target allocation accounted for 29.7 percent of total positive target allocations with the PECO Zone accounting for 7.9 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 29.0 percent of all negative target allocations, with the Western Hub accounting for 13.8 percent of total negative target allocations.

Figure 13-7 Ten largest positive and negative FTR target allocations summed by source: 2021/2022



The Effect of Fast Start Pricing on FTR Target Allocations

PJM implemented fast start pricing on September 1, 2021. As a result of these changes, PJM produces two separate dispatch and pricing solutions. The dispatch run results in dispatch instructions and matching prices, termed dispatch run locational marginal price, or DLMP. The DLMP prices are the prices that would have been the LMPs prior to fast start pricing. The pricing run results in the final prices used in settlements, termed pricing run locational marginal price, or PLMP. The two runs result in different sets of target allocations for the same FTR paths. Table 13-17 compares the target allocations that result from the pricing and dispatch runs for both self scheduled and all other FTRS for September 2021 through December 2021. The difference indicates whether the target allocations were increased or decreased as a result of fast start pricing.

Table 13-17 Pricing run and dispatch run FTR Target Allocations: September 2021 through December 2021

	Pricing Run	Dispatch Run	Difference	% Difference
Non-Self Scheduled	$374,963,133.5	$374,109,200.7	$853,932.8	0.2%
Self Scheduled	$68,875,580.1	$68,737,575.7	$138,004.4	0.2%

Surplus Congestion Revenue

Surplus congestion revenue is a misnomer. In fact, there is no such thing as surplus congestion revenue. The rights to all congestion revenue belong to load. Surplus congestion revenue, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs.

In the current design, surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues. In addition, FTR Auction revenue results from the prices paid by willing FTR buyers and should not be returned to FTR buyers for any reason and should be settled monthly.

Surplus day-ahead congestion is defined as the difference between the day-ahead congestion collected and FTR target allocations. Surplus FTR auction revenue is defined as the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and from FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Surplus congestion revenue is defined as the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month.[36] Beginning with the 2014/2015 planning period, PJM may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.[37] The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any shortfall in FTR target allocations for the current month or prior months in the planning period. Any remaining surplus is used to pay any shortfall in FTR target allocations for the entire planning period at the end of the planning period. Any remaining surplus is distributed to ARR holders.[38]

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Figure 13-8 shows the distribution of the monthly surplus congestion revenue distributed to FTR holders as if it were settled monthly. The figure shows the portions of total monthly surplus, represented by the total height of the bar, that are from day-ahead congestion surplus, represented by the blue portion of the bar, and from auction surplus, represented by the orange portion of the bar. The horizontal green lines represent the amount of revenue that FTRs were paid from the surplus to be made whole for that month. The height of the bar below the green line is the portion of auction surplus that went to FTR holders, and the height of the bar above the green line is the portion that would have gone to ARR holders at the end of the planning period, if nothing changed and this surplus was not provided to FTRs. If a green line is above the bar that means there was not enough surplus congestion in that month to make FTRs whole. For example, September 2020 did not have enough surplus congestion to make FTRs whole. Those FTRs were made whole using surplus revenue from previous months. Six of the first seven months of the 2021/2022 planning period did not have enough revenue to pay FTR target allocations, represented by lines that are entirely above the surplus bars, resulting in a payout ratio under 100 percent for the planning period.

The market rules should recognize that ARR holders have the right to all surplus congestion revenue, not just the remainder after funding FTRs. The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. In Figure 13-8 the amount represented by each bar would be assigned to ARR holders in every month. In the first seven months of the 2021/2022 planning period, $84.0 million of surplus congestion revenue was paid to FTR holders that would have been paid to ARR holders under the MMU recommendation.

36 Prior to the 2017/2018 planning period, the surplus congestion revenue was not the simple sum of the surplus FTR auction revenue and surplus day-ahead congestion because there were various cross market charges subtracted from FTR revenue, including M2M and competing use charges, which reduced available surplus congestion revenue.

37 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 28 (Dec. 15, 2021).

38 On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period allocated to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165 (2018).

Figure 13-8 Monthly surplus congestion and auction revenue distributed to FTR holders: June 2017 through December 2021[39]

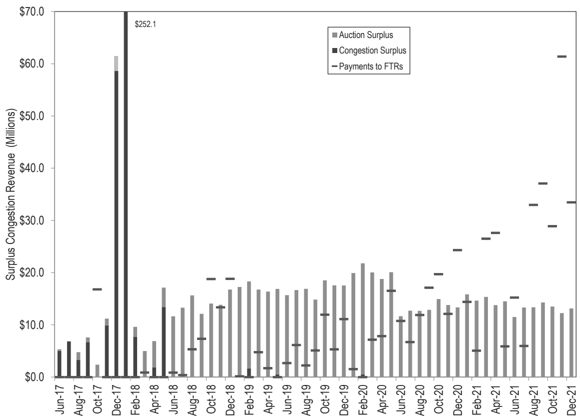


Figure 13-9 shows the surplus FTR auction revenue from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market model can result in large differences in FTR auction surplus and ARR revenue from one planning period to another.

FTR auction revenue is the value that FTR buyers assign to congestion rights that belong to ARR holders. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is inconsistent with the operation of a market that sellers are required to return some of the purchase price to buyers if the purchase is less profitable for buyers than expected. Auction revenue from the sale of FTRs should be distributed directly and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders on a monthly basis.

Figure 13-9 Monthly FTR auction surplus: 2011/2012 through 2021/2022

Table 13-18 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the first seven months of the 2021/2022 planning period.

Table 13-18 Surplus FTR Auction Revenue: 2010/2011 through 2021/2022[40]

Planning Period	Surplus FTR Auction Revenue (Millions)	Surplus Day-Ahead Congestion (Millions)	Surplus Congestion Revenue (Millions)
2010/2011	$29.7	($1,218.7)	($449.3)
2011/2012	$108.9	($460.3)	($192.5)
2012/2013	$66.7	($328.5)	($292.3)
2013/2014	$71.7	($715.3)	($678.7)
2014/2015*	$29.0	$139.8	$139.6
2015/2016	$29.6	$56.4	$42.5
2016/2017	$27.9	$97.1	$72.6
2017/2018	$27.4	$344.0	$371.2
2018/2019	$180.8	($68.5)	$112.3
2019/2020	$217.8	($87.9)	$140.7
2020/2021	$166.1	($185.1)	($14.5)
2021/2022**	$91.4	$215.0	($123.6)
Total	$1,047.0	($2,211.9)	($872.1)

*Start of counter flow "buy back"
**First seven months

39 The bars for December 2018 and January 2019 are truncated.

40 Total congestion surplus not equal to the sum of the columns in years prior to the 2017/2018 planning period because other charges were subtracted from the congestion surplus.

Revenue Adequacy

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs.

As defined, FTR revenue adequacy simply compares congestion revenues to FTR target allocations. (Target allocations are the CLMP differences between the source and sink of the FTR times the MW of the FTR.) There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations define the maximum payments to FTRs but target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment.

Actual congestion revenues are not a result of PJM's decisions about the FTR auction model. As a result, the fewer FTRs sold, the higher the probability that congestion will exceed the sum of the FTR target allocations. For example, PJM's subjective decision to reduce available system capability in the ARR/FTR market model through outage selection for the 2014/2015 through 2016/2017 planning periods resulted in a high level of revenue adequacy at the expense of a reduction in available ARRs and associated FTRs. PJM's decisions have included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced the FTRs made available for sale in FTR auctions. PJM's actions have led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

While PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. Instead, PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. The direct assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period increased the congestion revenue available to pay FTR holders. In response, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability. The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

Revenue adequacy for ARRs is, for practical purposes, a meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. Unsurprisingly, ARRs have been revenue adequate for every auction to date. ARR revenue adequacy has nothing to do with the adequacy of ARRs as an offset to total congestion. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load, or even much less.

Total net FTR auction revenue for the 2020/2021 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $691.2 million. The FTR auction revenue pays ARR holders' credits. For the first seven months of the 2021/2022 planning period, total net FTR auction revenue was $803.9 million.

Table 13-19 presents the PJM FTR revenue detail for the 2020/2021 planning period and the first seven months of the 2021/2022 planning period. This includes ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[41] In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from

41 The final ARR values may change if load shifts.

day-ahead congestion and does not include balancing congestion. A negative deficiency is a surplus, which will be distributed to ARR holders at the end of the planning period, while a positive deficiency is a shortfall, which will be charged as FTR uplift at the end of the planning period.

Table 13-19 Total annual ARR and FTR revenue detail (Dollars (Millions)): 2020/2021 and 2021/2022

Accounting Element	2020/2021	2021/2022*
ARR information		
ARR target allocations	$517.1	$626.8
ARR credits	$517.1	$626.8
FTR auction revenue	$691.2	$803.9
Annual FTR Auction net revenue	$577.0	$692.4
Long Term FTR Auction net revenue	$72.7	$69.9
Monthly Balance of Planning Period FTR Auction net revenue	$41.4	$41.6
Surplus auction revenue		
ARR Surplus	$166.1	$91.4
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$1,397.7	$1,312.5
Negative target allocations	($313.0)	($298.7)
FTR target allocations	$1,084.7	$1,013.8
Adjustments:		
Adjustments to FTR target allocations	($4.5)	$0.0
Total FTR targets	$1,080.3	$1,013.8
FTR payout ratio	98.7%	91.1%
FTR revenues		
ARR excess	$166.1	$91.4
Congestion		
Net Negative Congestion (enter as negative)	$0.0	$0.0
Hourly congestion revenue	$899.6	$798.8
M2M Payments(credit to PJM minus credit to M2M entity)	$0.0	$0.0
Adjustments:		
Surplus revenues carried forward into future months	$9.0	$3.6
Surplus revenues distributed back to previous months	$20.2	$3.7
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Surplus revenues distributed to other months	$29.2	$7.4
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$1,094.9	$897.6
Total congestion credits(includes end of year distribution)	$1,094.9	$897.6
Remaining deficiency	$14.5	$123.6

* First seven months of 2021/2022 planning period

FTR target allocations are defined based on hourly CLMP differences in the day-ahead energy market for FTR paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations but are capped at target allocations. Table 13-20 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month.

The total row in Table 13-20 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months. September 2020 had revenue shortfalls totaling $4.2 million, but September FTR target allocations were fully funded using surplus revenue from previous months. March and April 2021 had revenue shortfalls that could not be made whole using surplus revenues from previous months, resulting in a revenue shortfall for the planning period.

Table 13-20 Monthly FTR accounting summary (Dollars (Millions)): 2020/2021 and 2021/2022

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus/Deficiency (with adjustments)
Jun-20	$74.4	$73.3	100.0%	$74.7	100.0%	($1.1)
Jul-20	$118.3	$112.3	100.0%	$118.3	100.0%	($6.0)
Aug-20	$95.2	$94.4	100.0%	$95.2	100.0%	($0.8)
Sep-20	$90.9	$95.2	94.9%	$95.2	100.0%	$0.0
Oct-20	$67.5	$72.2	93.1%	$72.2	100.0%	$0.0
Nov-20	$55.1	$53.4	100.0%	$55.1	100.0%	($1.7)
Dec-20	$79.6	$90.5	87.5%	$90.5	100.0%	$0.0
Jan-21	$69.0	$67.6	100.0%	$69.0	100.0%	($1.4)
Feb-21	$104.9	$95.4	100.0%	$104.9	100.0%	($9.6)
Mar-21	$96.3	$107.5	89.6%	$105.5	98.2%	$1.1
Apr-21	$95.6	$109.4	87.4%	$95.6	87.4%	$13.4
May-21	$118.9	$110.3	100.0%	$118.9	100.0%	($8.6)
		Summary for Planning Period 2020/2021				
Total	$1,065.7	$1,081.5		$1,095.3		$14.5
Jun-21	$97.7	$101.5	96.3%	$101.5	100.0%	$0.0
Jul-21	$86.5	$79.1	100.0%	$86.5	109.3%	($7.4)
Aug-21	$121.5	$141.1	86.1%	$125.1	88.7%	$16.0
Sep-21	$110.7	$133.5	82.9%	$110.7	82.9%	$22.8
Oct-21	$126.7	$142.1	89.2%	$126.7	89.2%	$15.4
Nov-21	$220.9	$270.1	81.8%	$220.9	81.8%	$49.1
Dec-21	$126.1	$146.4	86.1%	$126.1	86.1%	$20.3
		Summary for Planning Period 2021/2022*				
Total	$890.2	$1,013.8		$423.8		$123.6

* First seven months of the 2021/2022 planning period

Figure 13-10 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through December 2021. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-10 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. The payout ratio for revenue inadequate months in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period.

Figure 13-10 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2021

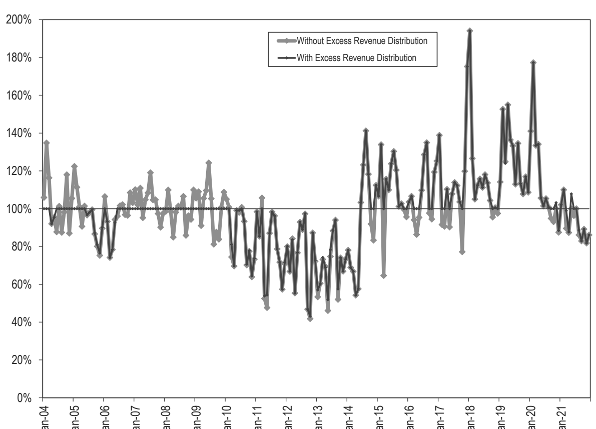


Table 13-21 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. The 2013/2014 planning period includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. Beginning with the 2018/2019 planning period payments to FTRs are limited to 100 percent of the target allocations.

The first seven months of the 2021/2022 planning period were revenue inadequate, with a payout ratio of 91.1 percent. Revenue inadequacy means that actual congestion revenue, excluding balancing congestion, is not enough to pay the target allocations for FTRs. Revenue inadequacy is generally a result of selling too many FTRs on a path compared to the actual capacity of the path. As revenue is the price difference on the path times the FTR MW, selling more MW of FTRs than can physically flow on the path will result in revenue inadequacy, unless excess revenue from other paths offsets the path with revenue shortfalls.

Table 13-21 Reported FTR payout ratio by planning period[42]

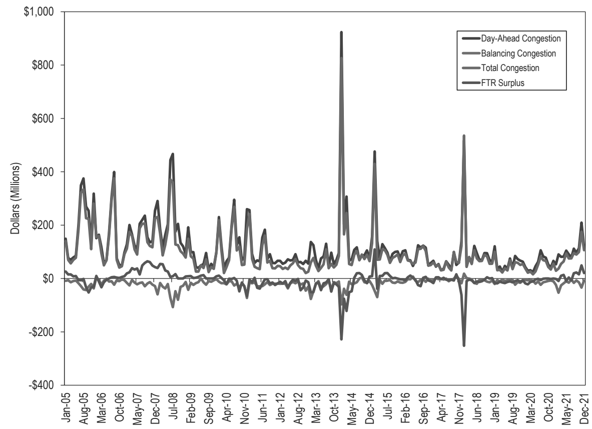
Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	116.2%
2015/2016	106.8%
2016/2017	112.6%
2017/2018	138.5%
2018/2019	100.0%
2019/2020	100.0%
2020/2021	98.7%
2021/2022	91.1%

* First seven months of 2021/2022

Figure 13-11 shows the day-ahead, balancing and total congestion payments from January 2005 through December 2021.

42 The actual payout ratios for planning periods 2006/2007, 2007/2008, and 2008/2009 may have exceeded 100 percent.

Figure 13-11 FTR surplus and day-ahead, balancing and total congestion: 2005 through December 2021



ARRs as an Offset to Congestion for Load

Load pays for the transmission system and pays congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load to offset an unintended consequence of locational marginal pricing. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion paid by load and the congestion paid to load, in aggregate and on a specific load basis. These inconsistencies between actual network use and path based rights cause cross subsidies between ARR holders and FTR holders and among ARR holders. One result of this misalignment is that individual zones have very different offsets due to the location of their path based ARRs compared to their actual congestion costs from actual network use.

Table 13-22 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. The highlighted offsets are the actual offsets based on the rules that were effective in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total day-ahead congestion and the load share of balancing and M2M payments.

The allocation of balancing congestion and M2M payments to load went into effect for the 2017/2018 planning period. If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,351.4 million less in congestion offsets from the 2011/2012 through the first seven months of the 2021/2022 planning period. The total overpayment to FTR holders for the 2011/2012 through the first seven months of the 2021/2022 planning period would have been $1,585.1 million.

Total ARR and self scheduled FTR revenue offset 44.8 percent of total congestion costs for the first seven months of the 2021/2022 planning period. For the 2019/2020 planning period, FTR bidders paid more in the auctions than the actual day-ahead target allocations for the same paths. The unexpected reduction in energy prices in 2020 led to a corresponding unexpected reduction in target allocations and in actual congestion. This resulted in an offset over 100 percent because the resulting total ARR value for the 2019/2020 planning period was greater than actual congestion costs. FTR prices were lower in the Annual FTR Auction for 2020/2021, reducing the offset for the 2020/2021 planning period.

Table 13-22 ARR and FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2021/2022

	Revenue								Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
Planning Period	ARR Credits	Unadjusted FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset	Cumulative Revenue	Offset
2011/2012	$515.6	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$775.0	103.4%	$585.5	78.1%	$663.8	88.5%	$775.0	103.4%
2012/2013	$356.4	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$530.7	101.1%	$263.2	50.2%	$306.9	58.5%	$530.7	101.1%
2013/2014	$339.4	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$826.5	44.2%	$556.3	29.7%	$556.3	29.7%	$826.5	44.2%
2014/2015	$487.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$872.2	64.2%	$678.4	50.0%	$967.8	71.3%	$872.2	64.2%
2015/2016	$641.8	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$860.2	90.4%	$745.5	78.4%	$892.3	93.8%	$860.2	90.4%
2016/2017	$648.1	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$813.1	104.1%	$729.6	93.4%	$872.1	111.7%	$813.1	104.1%
2017/2018	$429.6	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$694.2	58.2%	$592.8	49.7%	$883.1	74.1%	$592.8	49.7%
2018/2019	$531.6	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$655.87	96.4%	$525.3	77.2%	$621.3	91.4%	$621.3	91.4%
2019/2020	$547.6	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$637.9	144.1%	$491.7	111.1%	$627.9	141.8%	$627.9	141.8%
2020/2021	$392.7	$179.9	$899.6	($256.2)	$643.4	($43.2)	($0.0)	($0.0)	$529.31	82.3%	$316.4	49.2%	$316.4	49.2%	$316.4	49.2%
2021/2022*	$275.0	$166.3	$815.5	($105.4)	$710.0	($34.9)	($17.6)	($17.6)	$406.5	57.2%	$318.3	44.8%	$318.3	44.8%	$318.3	44.8%
Total	$5,165.1	$2,692.7	$12,253.5	($2,350.1)	$9,903.4	($256.2)	$295.4	$1,518.6	$7,601.6	76.8%	$5,803.1	58.6%	$7,026.3	70.9%	$7,154.4	72.2%

* seven months of 2021/2022 planning period

Table 13-22 illustrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

The cumulative offset, beginning in the 2011/2012 planning period, is the sum of the revenue received for that planning period and all previous planning periods divided by the total congestion for that planning period and all previous planning periods. The cumulative shortfall is the cumulative difference between the ARR holders' revenue and the congestion they paid, for the planning period and prior planning periods.

Table 13-23 also shows the cumulative offset and shortfall, assuming the rules implemented in the 2017/2018 planning period. The cumulative offset percentage has increased since the 2014/2015 planning period except for the 2019/2020 planning period. The cumulative offset would have been 70.9 percent if the 2017/2018 surplus allocation rules had been in place for the entire period.

Table 13-23 ARR and FTR cumulative offset for ARR holders using 2017/2018 surplus allocation: 2011/2012 through 2021/2022

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	88.5%	($85.9)
2012/2013	76.2%	($303.8)
2013/2014	48.6%	($1,618.1)
2014/2015	55.4%	($2,007.9)
2015/2016	62.1%	($2,066.6)
2016/2017	68.3%	($1,975.4)
2017/2018	69.2%	($2,284.8)
2018/2019	71.1%	($2,343.6)
2019/2020	74.8%	($2,158.3)
2020/2021	73.0%	($2,485.4)
2021/2022*	70.9%	($2,877.1)

* seven months of 2021/2022 Planning Period

Table 13-24 shows the cumulative offset and shortfall using the rules that were effective in the given planning period to calculate the ARR/FTR revenue. The cumulative offset was 72.2 percent based on the rules that were in place for each planning period. Load has been underpaid by $2.7 billion from the 2011/2012 planning period through the first seven months of the 2021/2022 planning period. The amount of underpayment would have been even greater, $4.1 billion, if the 2017/2018 surplus allocation rules had been in place for the entire period.

Table 13-24 ARR and FTR cumulative offset for ARR holders using effective surplus allocation rules: 2011/2012 through 2021/2022

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	103.4%	$25.3
2012/2013	102.4%	$31.2
2013/2014	67.8%	($1,012.9)
2014/2015	66.7%	($1,498.3)
2015/2016	70.9%	($1,589.2)
2016/2017	75.0%	($1,556.9)
2017/2018	71.0%	($2,156.7)
2018/2019	72.7%	($2,215.4)
2019/2020	76.3%	($2,030.2)
2020/2021	74.4%	($2,357.2)
2021/2022*	72.2%	($2,748.9)

* seven months of 2021/2022 Planning Period

Zonal ARR Congestion Offset

Zonal ARR congestion offsets vary significantly across zones. There is no reason that this should be the result. This outcome is a direct result of the flawed definition of congestion and of the method for assigning rights to congestion to ARR holders. The results show that path based ARR assignments in the current path based ARR/FTR design are not aligned with actual network use by load, and are therefore not aligned with how congestion is actually paid by load on actual network usage. Due to this misalignment of ARR rights relative to actual network usage, individual loads cannot claim the congestion they paid through assigned ARRs. The misalignment of path based ARR rights produces cross subsidies among ARR holders.

ARRs are allocated to zonal load based on historical generation to load transmission contract paths, in many cases based on 1999 contract paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load, including generation in the zone and outside the zone.[43]

Table 13-25 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue adjusted by the payout ratio for FTRs if below 100 percent; and the allocation of end of planning period surplus.[44] The offset for the first seven months of the 2021/2022 planning period assigns the current surplus revenue at the end of the quarter to ARR holders. Table 13-25 also shows payments by load for balancing congestion and M2M payments. The total congestion offset paid to load is the sum of all of those credits and charges.

The zonal offset percentage shown in Table 13-25 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone.

43 *See* "Constraint Based Congestion Calculations," PJM ARR FTR Market Task Force (July 17, 2020) <https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx>.

44 See *2020 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses

Table 13-25 Zonal ARR and FTR total congestion offset (in millions) for ARR holders: 2021/2022 planning period

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	$2.2	($0.0)	($1.1)	$0.0	$1.0	$7.2	($1.0)	($0.1)	$6.1	17.1%
AEP	$25.1	$25.5	($16.1)	$0.0	$34.5	$132.8	($15.1)	($1.0)	$116.7	29.6%
APS	$17.6	$12.9	($6.1)	$0.0	$24.5	$57.2	($5.7)	($0.4)	$51.1	47.8%
ATSI	$12.2	$0.5	($7.6)	$0.0	$5.2	$62.6	($7.0)	($0.5)	$55.1	9.4%
BGE	$52.8	$2.4	($3.8)	$0.0	$51.4	$30.8	($3.6)	($0.3)	$26.9	190.7%
COMED	$24.6	$4.3	($11.1)	$0.0	$17.8	$95.7	($10.3)	($0.8)	$84.6	21.1%
DAY	$3.0	$0.5	($2.1)	$0.0	$1.5	$15.3	($1.9)	($0.1)	$13.3	11.3%
DOM	$18.5	$76.8	($18.7)	$0.0	$76.6	$125.8	($17.8)	($0.1)	$107.9	71.0%
DPL	$21.8	$8.4	($2.3)	$0.0	$28.0	$34.7	($2.1)	($0.9)	$31.7	88.2%
DUKE	$14.6	$1.0	($3.1)	$0.0	$12.5	$22.9	($2.9)	($0.2)	$19.8	63.0%
DUQ	$3.3	$0.2	($1.5)	$0.0	$2.0	$9.9	($1.4)	($0.2)	$8.4	23.3%
EKPC	$2.3	$0.0	($1.5)	$0.0	$0.7	$12.3	($1.4)	($0.1)	$10.8	6.8%
EXT	$0.4	$0.0	($2.9)	$0.0	($2.5)	$13.2	($2.9)	$0.0	$10.3	(23.9%)
JCPLC	$1.2	$0.0	($2.7)	$0.0	($1.5)	$17.9	($2.5)	($0.2)	$15.2	(9.8%)
MEC	$4.6	$1.4	($5.1)	$0.0	$0.9	$19.7	($5.0)	($0.1)	$14.6	5.8%
OVEC	$0.0	$0.0	($0.1)	$0.0	($0.1)	$0.5	($0.1)	$0.0	$0.4	(21.0%)
PE	$6.0	$5.9	($2.5)	$0.0	$9.4	$19.9	($2.4)	($0.1)	$17.3	54.4%
PECO	$12.0	$0.3	($4.2)	$0.0	$8.1	$34.2	($3.8)	($0.3)	$30.1	26.8%
PEPCO	$13.5	$3.3	($3.5)	$0.0	$13.3	$27.0	($3.3)	($0.2)	$23.5	56.8%
PPL	$19.5	$7.1	($4.6)	$0.0	$22.0	$38.7	($4.2)	($0.3)	$34.2	64.5%
PSEG	$19.6	$1.3	($4.8)	$0.0	$16.1	$34.1	($4.4)	($0.4)	$29.3	55.0%
REC	$0.2	$0.0	($0.2)	$0.0	($0.0)	$3.0	($0.2)	($0.0)	$2.8	(0.3%)
Total	$275.0	$151.8	($105.4)	$0.0	$321.3	$815.5	($99.1)	($6.4)	$710.0	45.3%

The total congestion offset paid to loads in the first seven months of the 2021/2021 planning period was 45.3 percent of congestion costs. The results vary significantly by zone. Loads in some zones, like BGE, receive substantially more in offsets than their total congestion payments. Loads in other zones, like ATSI, receive substantially less in offsets than their total congestion payments. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions.

The amount and proportion of the offset that can be realized by load serving entities via their ARR allocations varies by planning period. The offsets are a function of the assignment of ARRs relative actual network sources of congestion paid, the valuation of ARRs in the FTR auctions and the congestion revenue from self scheduled ARRs. If the prices for FTRs are high relative to realized congestion, the offset provided by ARR is increased relative to cases where the prices for FTRs are low relative to realized congestion. While the amount of congestion that is returned to the load varies by planning period, PJM's ARR/FTR design has consistently failed to return the congestion revenues to the load that paid it. It is not possible for load to recover all of the congestion that they pay under the current design in which the rights to congestion revenues are assigned based on fictitious contract paths.

Offset if all ARRs are Held as ARRs

Table 13-26 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARRs holders held all their allocated ARRs in the 2019/2020, 2020/2021, and the first seven months of the 2021/2022 planning period and did not self schedule any.

Table 13-26 Offset available to load if all ARRs are held: 2019/2020 through 2021/2022 planning periods

	19/20 Planning Period				20/21 Planning Period				21/22 Planning Period*			
	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset
ACEC	$7.8	($2.1)	$3.7	155.9%	$4.4	($2.7)	$5.5	31.2%	$2.2	($1.1)	$6.1	17.8%
AEP	$169.0	($28.2)	$81.9	172.0%	$85.3	($38.1)	$110.9	42.6%	$53.7	($16.1)	$116.7	32.2%
APS	$63.8	($10.4)	$31.9	167.3%	$50.5	($14.8)	$45.2	79.0%	$26.8	($6.1)	$51.1	40.6%
ATSI	$35.4	($13.9)	$36.8	58.3%	$20.5	($19.5)	$50.6	2.1%	$12.5	($7.6)	$55.1	9.0%
BGE	$67.1	($6.7)	$15.3	396.2%	$61.1	($9.1)	$24.8	209.2%	$54.8	($3.8)	$26.9	189.0%
COMED	$64.2	($19.8)	$65.2	68.1%	$43.2	($28.5)	$78.3	18.8%	$27.9	($11.1)	$84.6	19.9%
DAY	$11.4	($3.9)	$9.7	77.2%	$6.4	($5.3)	$11.0	9.8%	$3.4	($2.1)	$13.3	9.8%
DOM	$67.4	($16.9)	$59.2	85.2%	$67.5	($37.9)	$87.9	33.7%	$61.6	($3.1)	$107.9	54.2%
DPL	$50.9	($8.7)	$17.4	242.4%	$32.8	($6.7)	$36.2	72.0%	$28.2	($1.5)	$31.7	84.1%
DUKE	$44.2	($6.0)	$14.9	256.9%	$28.8	($8.4)	$17.4	117.5%	$16.5	($18.7)	$19.8	(10.8%)
DUQ	$5.4	($3.2)	$5.1	43.0%	$5.8	($4.0)	$6.2	28.7%	$3.4	($2.3)	$8.4	13.6%
EKPC	$2.4	($2.9)	$7.4	(7.2%)	$3.0	($4.2)	$8.4	(13.3%)	$2.3	($1.5)	$10.8	6.9%
EXT	$2.0	($2.2)	($1.7)	10.6%	$0.5	($13.8)	$11.0	(120.7%)	$0.4	($2.9)	$10.3	(23.9%)
JCPLC	$6.0	($4.6)	$9.2	14.5%	$6.1	($6.1)	$12.9	(0.1%)	$1.2	($2.7)	$15.2	(10.0%)
MEC	$7.7	($4.2)	$8.7	40.2%	$3.9	($5.3)	$16.5	(8.4%)	$5.1	($5.1)	$14.6	(0.3%)
OVEC	NA	$0.1	$0.5	14.6%	NA	($0.3)	$0.9	(28.8%)	NA	($0.1)	$0.4	(21.0%)
PE	$18.1	($3.8)	$10.8	132.3%	$9.3	($6.5)	$16.4	16.7%	$8.7	($4.2)	$17.3	25.9%
PECO	$24.0	($8.2)	$13.4	118.3%	$15.1	($10.9)	$24.9	17.0%	$12.2	($2.5)	$30.1	32.0%
PEPCO	$30.6	($6.1)	$13.7	178.3%	$29.1	($8.3)	$20.5	101.6%	$15.5	($3.5)	$23.5	51.0%
PPL	$37.6	($8.5)	$20.5	142.2%	$26.1	($11.5)	$30.8	47.4%	$21.4	($4.6)	$34.2	49.4%
PSEG	$46.2	($8.9)	$18.4	202.5%	$24.7	($13.9)	$25.0	43.2%	$20.2	($4.8)	$29.3	52.7%
REC	$0.6	($0.3)	$0.6	46.2%	$0.2	($0.6)	$2.1	(17.0%)	$0.2	($0.2)	$2.8	(0.3%)
Total	$761.8	($169.4)	$442.7	133.8%	$524.3	($256.2)	$643.4	41.7%	$378.0	($105.4)	$710.0	38.4%

* First seven months of the 2021/2022 planning period

Offset if all ARRs are Self Scheduled

Table 13-27 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARR holders self scheduled all their allocated ARRs as FTRs in the 2019/2020, 2020/2021, and the first seven months of the 2021/2022 planning period. The calculated self scheduled FTR target allocations assume a 100 percent payout ratio. The results show that the recovery of congestion varies significantly by zone and that the load in some zones recovers more than the congestion paid and the load in other zones recovers less. This result is not consistent with a rational FTR/ARR design under which all load would be returned their congestion, but no more and no less.

Table 13-27 Offset available to load if all ARRs self scheduled: 2019/2020 through 2021/2022 planning periods

	19/20 Planning Period				20/21 Planning Period				21/22 Planning Period*			
	SS FTR	Bal+M2M Charges	Congestion+ M2M	Offset	SS FTR	Bal+M2M Charges	Congestion+ M2M	Offset	SS FTR	Bal+M2M Charges	Congestion+ M2M	Offset
ACEC	$2.6	($2.1)	$3.7	15.6%	$1.8	($2.7)	$5.5	(16.4%)	$0.3	($1.1)	$6.1	(12.9%)
AEP	$62.7	($28.2)	$81.9	42.1%	$77.3	($38.1)	$110.9	35.3%	$67.3	($16.1)	$116.7	43.9%
APS	$31.2	($10.4)	$31.9	65.1%	$42.0	($14.8)	$45.2	60.3%	$39.5	($6.1)	$51.1	65.4%
ATSI	$27.9	($13.9)	$36.8	38.1%	$30.7	($19.5)	$50.6	22.1%	$34.4	($7.6)	$55.1	48.8%
BGE	$53.7	($6.7)	$15.3	308.0%	$79.7	($9.1)	$24.8	284.2%	$80.3	($3.8)	$26.9	283.8%
COMED	$40.6	($19.8)	$65.2	31.9%	$69.6	($28.5)	$78.3	52.4%	$40.4	($11.1)	$84.6	34.6%
DAY	$5.6	($3.9)	$9.7	17.4%	$8.0	($5.3)	$11.0	24.9%	$5.4	($2.1)	$13.3	25.2%
DOM	$32.8	($16.9)	$59.2	26.9%	$117.0	($37.9)	$87.9	90.0%	$121.9	($3.1)	$107.9	110.1%
DPL	$27.3	($8.7)	$17.4	107.3%	$56.4	($6.7)	$36.2	137.4%	$44.1	($1.5)	$31.7	134.5%
DUKE	$30.5	($6.0)	$14.9	164.2%	$40.9	($8.4)	$17.4	187.2%	$31.8	($18.7)	$19.8	66.1%
DUQ	$8.1	($3.2)	$5.1	95.2%	$8.9	($4.0)	$6.2	79.7%	$6.8	($2.3)	$8.4	54.0%
EKPC	$4.1	($2.9)	$7.4	16.8%	$6.6	($4.2)	$8.4	29.3%	$5.8	($1.5)	$10.8	39.4%
EXT	$0.9	($2.2)	($1.7)	74.3%	$0.3	($13.8)	$11.0	(122.3%)	$0.7	($2.9)	$10.3	(21.2%)
JCPLC	$2.3	($4.6)	$9.2	(25.5%)	$0.9	($6.1)	$12.9	(40.2%)	$2.8	($2.7)	$15.2	0.4%
MEC	$0.8	($4.2)	$8.7	(38.5%)	$8.0	($5.3)	$16.5	16.5%	$18.1	($5.1)	$14.6	89.0%
OVEC	NA	$0.1	$0.5	NA	NA	($0.3)	$0.9	NA	NA	($0.1)	$0.4	(21.0%)
PE	$11.2	($3.8)	$10.8	69.1%	$13.5	($6.5)	$16.4	42.8%	$13.3	($4.2)	$17.3	52.9%
PECO	$16.8	($8.2)	$13.4	63.8%	$14.0	($10.9)	$24.9	12.4%	$16.0	($2.5)	$30.1	44.7%
PEPCO	$23.2	($6.1)	$13.7	124.3%	$37.3	($8.3)	$20.5	141.7%	$30.7	($3.5)	$23.5	116.1%
PPL	$39.2	($8.5)	$20.5	149.9%	$43.7	($11.5)	$30.8	104.5%	$80.9	($4.6)	$34.2	223.6%
PSEG	$21.3	($8.9)	$18.4	67.2%	$43.2	($13.9)	$25.0	117.0%	$34.2	($4.8)	$29.3	100.3%
REC	$0.2	($0.3)	$0.6	(22.6%)	$1.0	($0.6)	$2.1	21.0%	$0.6	($0.2)	$2.8	16.0%
Total	$443.0	($169.4)	$442.7	61.8%	$700.9	($256.2)	$643.4	69.1%	$675.3	($105.4)	$710.0	80.3%

* First seven months of the 2021/2022 planning period

ARR Allocation and Congestion In and Out of Zone

Table 13-28 shows the share of ARR MW for the 2021/2022 planning period with paths that source inside and outside the zone where the ARR load is located, and the proportion of congestion that results from constraints that are inside and outside the zone. Table 13-28 allows a comparison of externally sourced ARRs with the congestion that results from external constraints. For example, 93.5 percent of ACEC congestion results from constraints that are outside of the zone, but only 27.8 percent of ACEC ARRs originate outside the zone.

Table 13-28 illustrates one of the fundamental issues with the path based approach to ARR/FTR design. In the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load, but the assignment of ARRs is inconsistent with that fact. This inconsistency makes it impossible for load to match ARRs with the actual sources of congestion.

Table 13-28 ARR Allocation and Congestion from inside and outside zone: 2021/2022

	ARRs		Congestion	
	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	27.8%	72.2%	93.5%	6.5%
AEP	10.4%	89.6%	78.5%	21.5%
APS	10.5%	89.5%	96.7%	3.3%
ATSI	21.2%	78.8%	98.0%	2.0%
BGE	44.8%	55.2%	83.9%	16.1%
COMED	0.0%	100.0%	79.9%	20.1%
DAY	72.2%	27.8%	96.1%	3.9%
DOM	0.4%	99.6%	73.3%	26.7%
DPL	31.7%	68.3%	34.2%	65.8%
DUKE	29.6%	70.4%	91.2%	8.8%
DUQ	82.6%	17.4%	97.9%	2.1%
EKPC	49.5%	50.5%	99.9%	0.1%
EXT	100.0%	0.0%	92.3%	7.7%
JCPL	18.9%	81.1%	100.0%	0.0%
OVEC	NA	NA	49.7%	50.3%
MEC	30.3%	69.7%	94.7%	5.3%
PE	16.9%	83.1%	85.1%	14.9%
PECO	10.3%	89.7%	75.7%	24.3%
PEPCO	22.3%	77.7%	96.7%	3.3%
PPL	1.3%	98.7%	70.6%	29.4%
PSEG	34.8%	65.2%	99.5%	0.5%
REC	100.0%	0.0%	33.9%	66.1%
Average	34.1%	65.9%	82.8%	17.2%

Credit

There were 10 collateral defaults in 2021. There were 10 payment defaults not involving GreenHat Energy, LLC for a total of $2.3 million. GreenHat Energy's default payments ended with the 2020/2021 planning period for a total of $179.5 million. Of the 20 defaults, 15 were promptly cured, and the remainder are awaiting resolution.

On December 21, 2021, PJM submitted a change to the credit rules to FERC.[45] Under the proposed rules PJM would replace the current credit calculation, which is largely based on a weighted average historical FTR value, with an initial margin based on a risk confidence interval from an historical simulation analysis model. PJM's proposal included the use of a 97 percent confidence interval, which indicates a 97 percent probability that the initial margin collected would cover potential default costs. The MMU recommends the use of a 99 percent confidence interval when calculating the initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions.

Default Portfolio Considerations

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market and will continue to accrue revenues and/or charges and must be reconciled. Under this method, PJM leaves the participant's positions unchanged, lets the positions settle at day-ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends a method under which defaulted FTRs would be canceled rather than holding or liquidating them. Canceling the FTRs would release the FTRs to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There would be no discretion necessary to settle the defaulted position and the losses would be contained within the ARR/FTR market.

45 *See* "Revisions to PJM's FTR Credit Requirement and Request for 28-Day Comment Period," Docket No. ER22-000 (December 21, 2021).

Cancellation of a defaulting portfolio does not change congestion. But cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs would isolate the costs of the default to those participating in and benefitting from the FTR market.

FTR Forfeitures

By order issued January 19, 2017, the Commission determined that the FTR forfeiture rule is just and reasonable and "...serves to deter such manipulation" related to virtual transaction cross product manipulation.[46] The Commission identified four main tenets with which the Forfeiture Rule must comply, including that it: deter manipulation, provide transparency allowing participants to modify their behavior, base forfeitures on an individual participant's actions and is not punitive.[47]

The point of the FTR forfeiture rule is to avoid an inefficient and costly market power mitigation process and to establish an objective rule that prevents manipulation of the FTR market. The FTR forfeiture rule is designed to remove the incentive to engage in manipulation. The rule does not result in findings of manipulation.[48]

The FTR forfeiture rule considers the impact of a participant's net virtual transaction portfolio on all constraints.[49] If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the constraint line limit, and that constraint affects an individual FTR's target allocation by $0.01 or more, the participant's net virtual portfolio increased the value of the FTR, and the FTR is subject to FTR forfeiture. The FTR forfeiture also requires that congestion on the FTR path in the day ahead market be greater than congestion on that path in the real time market.

The FTR forfeiture rule does not require FTR holders to pay penalties. The FTR forfeiture rule does not affect the profits or losses of virtual activity. The FTR forfeiture rule, if triggered by a participant's virtual portfolio, results in forfeiting only FTR profits and only in the specific hours for which the rule is violated. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Even when FTR profits are forfeited, the value that the buyer assigned to congestion in the FTR auction (the price paid) is not affected. For example, if a buyer paid $5.00/MWh for congestion and congestion was $5.00/MWh, the forfeiture would be zero. If congestion were $7.00/MWh, the forfeiture would be $2.00/MWh. Market participants understand the relationship between FTR and virtual positions in detail and can avoid violating the FTR forfeiture rule if they choose to do so.

The FTR forfeiture rule is less effective than initially intended as a result of the element of the rule requiring that day ahead congestion on the FTR path be greater than real time congestion the same path. As a result of model differences, there is a significant opportunity for virtual participants to profit from differences between day ahead and real time prices without driving the prices together, termed false arbitrage. As a result, FTR holders can use virtual positions to make their FTR positions more valuable without violating the rule.

The FTR forfeiture rule has not reduced participation in the PJM FTR market or participation in virtual activity. There has been an increase in the number of participants in the FTR market since the implementation of the new FTR forfeiture rule, and a decrease in the number of participants with forfeitures.

On June 24, 2019, PJM implemented a new method to calculate the hourly cost of an FTR only for hours in which it is effective.[50] Beginning with the September 2019 bill, PJM began billing using the correct hourly cost calculation. For the 2020/2021 planning period, total FTR forfeitures were $4.6 million.

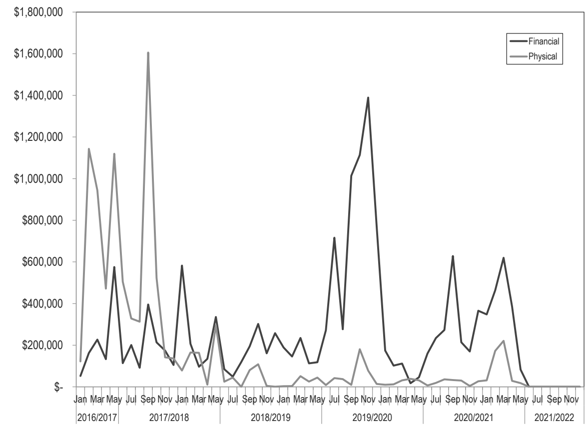
46 See 158 FERC ¶ 61,038 at P 33 (2017).
47 See *id.* at P 62.
48 *See* "Protest and Motion for Rejection of the Independent Market Monitor for PJM," Docket No. EL20-41 (June 1, 2020).
49 A modified FTR forfeiture rule was implemented effective January 19, 2017. See *2019 State of the Market Report for PJM*, Volume II, Section 13: Financial Transmission Rights for the full history.
50 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).

On May 20, 2021, FERC issued an order ruling the $0.01 definition of an increase in the value of an FTR unjust and unreasonable, but upheld the other parts of PJM's forfeiture rule.[51] In this order, FERC required PJM to modify the FTR forfeiture rule and submit a compliance filing. As a result, there was no FTR forfeiture rule in place from May 20, 2021 through the end of 2021.

On June 21, 2021, PJM filed a request for clarification, or alternatively rehearing.[52] PJM asked that FERC clarify the status of the forfeitures that were assessed over the four years between the initial FERC order for a compliance filing, and their order rejecting PJM's compliance filing. On July 19, 2021, PJM made a compliance filing to address FERC's concerns with the $.01 element of the FTR forfeiture rule.[53] PJM's compliance filing eliminated that element and replaced it with a constraint based FTR forfeiture. The forfeiture is based on the increased value of each constraint that violates the rule, determined by the shadow price multiplied by the net dfax on that constraint. This change meets FERC's previously established criteria established under the initial FERC order and creates a more precise FTR forfeiture value, to meet the criteria established under the new FERC order.

Figure 13-12 shows the monthly FTR forfeitures under the modified FTR forfeiture rule from January 19, 2017, through December 31, 2021. As required by the FERC order, PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the period from January 2017 through September 2017, participants did not have good information about the level of their FTR forfeitures, so they could not accurately modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures decreased significantly, and stabilized, as participants received information on their FTR forfeitures.

Figure 13-12 Monthly FTR forfeitures for physical and financial participants



51 See 175 FERC ¶ 61,137 (2021).
52 *See* "Request for Clarification or, in the Alternative, Rehearing of PJM Interconnection, LLC," FERC Docket No. ER17-1433-00 (June 21, 2021).
53 *See* "FTR Forfeiture Rule Compliance Filing," FERC Docket No. ER17-1433 (July 19, 2021).

DATA REQUEST

KPSC PHDR_10 Refer to Kentucky Power's response to Commission Staff's First Request for Information (Staff's First Request), Item 16. Refer also to Kentucky Power's response to the Attorney General's First Request for Information (Attorney General's First Request), Item 1, KPCO_R_AG_1_1_ConfidentialAttachment1.

a.: Identify the specific request for proposal (RFP) responses that were used to calculate the amounts reflected in the PPAs tab of KPCO_R_AG_1_1_ConfidentialAttachment1.

b.: Identify the specific files and page numbers provided in response to Kentucky Power's response to Staff's First Request, Item 16 that include the pricing information used to calculate the amounts in the PPAs tab of KPCO_R_AG_1_1_ConfidentialAttachment1. Include in the response an explanation of how the pricing information was used to get to the amounts reflected in that spreadsheet.

c.: Identify and explain any changes to the PPA prices between the date of the initial responses and any update in or after 2024 for the PPAs used to calculate the amounts in the PPAs tab of KPCO_R_AG_1_1_ConfidentialAttachment1.

RESPONSE

a.-c. The information provided in Staff's First Request, Item 16 only contained the initial bid information for responses to the 2023 RFP. For the updated bid prices that were submitted post 111d rules and used in KPCO_R_AG_1_1_ConfidentialAttachment1 on the PPA tab, please see KPCO_R_KPSC_PHDR_10_ConfidentialAttachment1 ([redacted] submitted by [redacted]) and KPCO_R_KPSC_PHDR_10_ConfidentialAttachment2 ([redacted] submitted by [redacted]).

For the original bid and full terms of the PPA listed in row 11 of the PPA tab in KPCO_R_AG_1_1_ConfidentialAttachment1, please see the files contained within the [redacted] folder. These files can be located by opening the KPCO_R_KPSC_1_16_ConfidentialAttachment1 file and clicking [redacted] and [redacted]. For the PPA listed in row 4 of the PPA tab in KPCO_R_AG_1_1_ConfidentialAttachment1, please see the files contained within the [redacted] folder. These files can be located by opening the KPCO_R_KPSC_1_16_ConfidentialAttachment1 file and clicking [redacted] and [redacted].

Witness: Alex E. Vaughan

Nicole M Coon

From:	Zachary M Yetzer
Sent:	Thursday, May 16, 2024 8:20 AM
To:	[redacted]
Subject:	RE: [redacted]

Thanks [redacted] I'll get the team moving on this asap.

From: [redacted]
Sent: Thursday, May 16, 2024 8:19 AM
To: Zachary M Yetzer <zmyetzer@aep.com>; Jay F Godfrey <jfgodfrey@aep.com>
Subject: [EXTERNAL] RE: [redacted]

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This is an **EXTERNAL** email. **STOP. THINK** before you click links or open attachments. If suspicious, please click the **'Report to Incidents'** button. No button, forward to incidents@aep.com.

Zach,

Thank you for confirming receipt. No changes in any of the other parameters.

Regards,
[redacted]

From: Zachary M Yetzer <zmyetzer@aep.com>
Sent: Thursday, May 16, 2024 8:12 AM
To: [redacted] Jay F Godfrey <jfgodfrey@aep.com>
Subject: RE: [redacted]

Warning External Email

[redacted]

Thanks for the email. Confirming receipt. I note that you said the proposed structure would remain the same, I just want to double check on the Start Charges and Variable O&M. There was no change to the pricing for those 2 buckets, correct?

Zach

From: [redacted]
Sent: Thursday, May 16, 2024 1:02 AM
To: Zachary M Yetzer <zmyetzer@aep.com>; Jay F Godfrey <jfgodfrey@aep.com>
Subject: [EXTERNAL] [redacted]

Jay and Zach,

It was good to catch up with you earlier today. As we discussed on the phone, the fundamental shift we see coming in the future has made us uncomfortable with the original price we submitted in November. The structure we proposed would remain the same and every discussion we have had to this point would still stand, but the new price would be [redacted]mo. Please let us know when your feedback once you have had a chance to evaluate.

Thanks,
[redacted]

[redacted]

[redacted]

Nicole M Coon

From: [redacted]
Sent: Thursday, May 23, 2024 12:28 PM
To: KPCO2023RFP
Cc: Joseph A Karrasch; Zachary M Yetzer; Jay F Godfrey; Ashley R Lawson; tromaine
Subject: [EXTERNAL] RE: KPCo 2023: Reconfirmed or Reprice Bid Request

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This is an **EXTERNAL** email. **STOP. THINK** before you click links or open attachments. If suspicious, please click the **'Report to Incidents'** button. No button, forward to incidents@aep.com.

AEP Team,

Please see below updated pricing for [redacted] bids into this RFP and additional clarifications.

1. [redacted] agrees with conceptual treatment of Environmental Change in Law (i.e. US EPA or State EPA issues requirements for New or Existing Fossil Fuel Fired Electricity Generators under Section 111(d)), subject to final agreement on definitive language.
2. For the first 3 Delivery Years, the Capacity from the project will be offered into the PJM capacity market by the Seller under the market rules in place at the time. The revenues for the sale of capacity by Seller to PJM will be passed through to Buyer. Any Capacity Performance penalties or bonuses charged or credited by PJM for this capacity will also be passed through to Buyer on the next invoice.
3. Aside from the changes noted below, all commercial terms from the original bid hold. [redacted] will also no longer be offering a [redacted] option for [redacted]

[redacted]

Thank you again for the opportunity and let us know if you have any further questions.

Best,

[redacted]

Upcoming PTO: 5/24 – 6/5

From: KPCO2023RFP
Sent: Friday, May 17, 2024 10:04 AM
To: KPCO2023RFP

Cc: Joseph A Karrasch ; Zachary M Yetzer ; Jay F Godfrey ; Ashley R Lawson
Subject: [EXTERNAL] KPCo 2023: Reconfirmed or Reprice Bid Request

Good morning,

In response to the uncertainty associated with recent market changes, the EPA rulemaking for Carbon Pollution Standards for New and Existing Fossil-Fuel Fired Electricity Generators, and the time that has elapsed since bids associated with the RFP were received, Kentucky Power Company is requesting that all Bidders in the Thermal RFP either reconfirm or reprice their Bids, with the changes noted below.

Reconfirmed or Reprice Bid Request: Please respond to this email (**reply all**) by EOD on **Wednesday, May 22** with your bid price and confirmation of the following:

1. Bid price to include a mutual termination provision for a Environmental Change in Applicable Law (i.e. US EPA or State EPA issues requirements for New or Existing Fossil Fuel Fired Electricity Generators under Section 111(d)), should both sides be unable to come to agreement on a change in the Contract Rate associated with a New or Existing Fossil Fuel Fired Electricity Generator impacted by an Environmental Change in Applicable Law, with any termination date on the Contract to occur prior to the date such new requirements are fully implemented at the applicable plant and,
2. Bid price assumes a Financial Settlement (swap) for Capacity for the first 3 Delivery Years where Seller would be provided a fixed Capacity price from Purchaser, settled financially, as Seller would still bid the physical Capacity of the Facility into PJM's Base Residual Auction, and under the financial settlement, Kentucky Power Company would be responsible for the floating price.

Please reply all to this email. If you have any questions, please contact Joe Karrasch at [redacted] or [redacted]

Thank you,

KPCo RFP Team

Kentucky Power Company
KPSC Case No. 2025-00175
Commission Staff's Set of Post-Hearing Data Requests
Dated November 21, 2025

DATA REQUEST

KPSC PHDR_11 Refer to Kentucky Power's response to Attorney General's First Request,
a. Item 1, KPCO_R_AG_1_1_ConfidentialAttachment1, Tab Market. Provide a monthly breakdown of the Generation, Revenue, and Total Generation Cost information provided in lines 1 through 13, columns A through J of the Market tab of KPCO_R_AG_1_1_ConfidentialAttachment1.

b. For each month from January 2023 to the most recent month for which information is available, provide a monthly breakdown of the energy produced by Mitchell Unit 1 and Mitchell Unit 2, the revenue from sales of energy from each unit, and the variable cost of producing energy for each unit, with the variable costs broken out between fuel costs and other variable O&M.

RESPONSE

a. Please see KPCO_R_KPSC_PHDR_11_Attachment1 for the requested information.

b. Please see KPCO_R_KPSC_PHDR_11_Attachment2 for the requested information.

Witness: Alex E. Vaughan

Kentucky Power Company
Mitchell Unit(s) Net Generation, Energy Revenues, Incremental Fuel Expense, & Incremental O&M Espense[1]
January 2023 - October 2025

	Mitchell Unit 1				Mitchell Unit 2			
Month	**Net Generation (MWh)**	**Incremental Fuel Expense ($)**	**Incremental Variable O&M Expense ($)**	**Energy Revenues ($)**	**Net Generation (MWh)**	**Incremental Fuel Expense ($)**	**Incremental Variable O&M Expense ($)**	**Energy Revenues ($)**
Jan-23	10,910	$ 302,013	$ 40,305	$ 407,570	24,228	$ 793,017	$ 103,443	$ 822,706
Feb-23	118,744	$ 3,351,213	$ 433,027	$ 3,013,450	242,386	$ 7,374,601	$ 957,250	$ 6,793,760
Mar-23	189,232	$ 5,381,379	$ 622,419	$ 5,397,869	185,527	$ 5,532,619	$ 646,168	$ 5,457,038
Apr-23	111,425	$ 2,947,250	$ 390,293	$ 3,258,091	7,907	$ 286,602	$ 29,333	$ 198,716
May-23	92,770	$ 2,510,672	$ 349,168	$ 2,728,840	125,491	$ 3,543,578	$ 491,030	$ 4,242,081
Jun-23	222,073	$ 6,530,435	$ 868,246	$ 6,674,421	232,871	$ 6,973,605	$ 916,777	$ 6,283,608
Jul-23	296,123	$ 8,657,747	$ 1,099,433	$ 9,932,991	435,486	$ 13,298,022	$ 1,685,062	$ 15,470,511
Aug-23	181,659	$ 5,127,388	$ 625,113	$ 5,378,279	302,206	$ 9,223,415	$ 1,125,608	$ 8,631,354
Sep-23	67,395	$ 2,380,525	$ 248,174	$ 2,189,244	93,243	$ 3,361,044	$ 351,935	$ 2,812,125
Oct-23	0	$ -	$ -	$ -	0	$ -	$ -	$ -
Nov-23	0	$ -	$ -	$ -	90,156	$ 4,413,422	$ 362,336	$ 2,946,105
Dec-23	34,618	$1,183,222.64	$118,953.12	$ 831,005	263,155	$ 9,702,115	$ 960,807	$ 6,901,883
Jan-24	26,870	$ 893,628	$ 81,092	$ 721,169	324,913	$ 11,831,606	$ 1,073,790	$ 16,352,369
Feb-24	198,216	$ 7,934,710	$ 636,510	$ 4,485,628	94,802	$ 3,881,418	$ 311,705	$ 2,187,631
Mar-24	156,186	$ 4,398,438	$ 495,316	$ 3,318,840	257,189	$ 7,717,758	$ 867,195	$ 5,660,452
Apr-24	102,515	$ 3,968,096	$ 344,731	$ 2,781,813	43,337	$ 1,777,992	$ 151,739	$ 1,135,475
May-24	0	$ -	$ -	$ -	67,164	$ 1,974,448	$ 253,016	$ 2,400,192
Jun-24	238,512	$ 7,044,223	$ 840,754	$ 7,695,871	329,765	$ 10,194,093	$ 1,221,418	$ 9,139,597
Jul-24	281,057	$ 8,200,718	$ 1,272,448	$ 11,253,457	254,692	$ 7,597,505	$ 1,178,852	$ 8,020,446
Aug-24	182,161	$ 5,330,928	$ 661,399	$ 5,839,231	266,149	$ 8,367,582	$ 1,040,503	$ 7,701,321
Sep-24	53,588	$ 2,233,591	$ 208,450	$ 1,170,839	0	$ -	$ -	$ -
Oct-24	226,396	$ 6,700,081	$ 867,918	$ 7,788,478	78,592	$ 2,362,736	$ 304,963	$ 2,723,190
Nov-24	236,729	$ 6,691,966	$ 39,332	$ 7,293,076	179,323	$ 5,391,216	$ 31,659	$ 5,424,360
Dec-24	269,564	$ 8,509,620	$ 33,131	$ 9,747,040	222,726	$ 7,558,140	$ 29,433	$ 8,152,718
Jan-25	357,830	$ 11,754,131	$ 1,033,595	$ 21,333,418	237,077	$ 8,112,413	$ 712,208	$ 15,859,816
Feb-25	21,428	$ 739,771	$ 61,873	$ 676,583	150,201	$ 6,292,554	$ 513,131	$ 9,474,575
Mar-25	0	$ -	$ -	$ -	53,308	$ 3,595,196	$ 194,140	$ 2,003,117
Apr-25	0	$ -	$ -	$ -	297,983	$ 9,823,192	$ 1,123,021	$ 14,069,751
May-25	0	$ -	$ -	$ -	78,399	$ 2,847,154	$ 266,047	$ 2,933,897
Jun-25	130,729	$ 4,196,060	$ 471,164	$ 8,820,904	175,423	$ 5,992,574	$ 671,137	$ 10,360,870
Jul-25	172,360	$ 5,218,307	$ 554,283	$ 10,501,649	350,282	$ 11,436,270	$ 1,216,199	$ 19,236,502
Aug-25	135,985	$ 4,351,549	$ 494,377	$ 6,527,366	262,120	$ 8,655,616	$ 976,804	$ 10,007,263
Sep-25	127,673	$ 4,477,448	$ -	$ 6,636,425	0	$ -	$ -	$ -
Oct-25	307,106	$ 9,519,053	$ 970,689	$ 15,898,910	199,105	$ 6,577,417	$ 670,721	$ 9,892,142

[1]Provided on a total plant basis.

DATA REQUEST

KPSC PHDR_12 Refer to Kentucky Power's response to Commission Staff's Fourth Request for Information (Staff's Fourth Request), Item 2(g). Refer to Kentucky Power's response to Attorney General's First Request, Item1, KPCO_R_AG_1_1_ConfidentialAttachment1, Tabs PPAs and Market.

a. Provide a breakdown of the annual energy production, revenue, and variable costs produced by the production cost run(s) used to calculate the "Energy Margins" for each of the PPAs provided on the PPAs tab of KPCO_R_AG_1_1_ConfidentialAttachment1.

b. Provide the workpapers tying the revenue and variable costs produced by the production cost run(s) to the "Energy Margins" reflected in the PPAs tab of KPCO_R_AG_1_1_ConfidentialAttachment1.

RESPONSE

a-b. Please see KPCO_R_KPSC_PHDR_12_ConfidentialAttachment1. Please note, in order to see to the PPAs that are used on the PPA tab within KPCO_R_AG_1_1_ConfidentialAttachment1, the corresponding project scenario must be selected within KPCO_R_KPSC_PHDR_12_ConfidentialAttachment1 on the Project_Costs tab in cell G5. For [redacted], please select [redacted] and for [redacted], please select [redacted] The amounts used for Energy Margins can be seen on the Dispatch_Net_Values tab and all underlying assumptions and calculations are intact.

Witness: Alex E. Vaughan

KPCO_R_KPSC_PHDR_12_ConfidentialAttachment1 is redacted in its entirety.

Kentucky Power Company
KPSC Case No. 2025-00175
Commission Staff's Set of Post-Hearing Data Requests
Dated November 21, 2025

DATA REQUEST

KPSC PHDR_13	Refer to Kentucky Power's response to Staff's Fourth Request, Item 1, KPCO_R_KPSC_4_1_Attachment1. Refer also to Kentucky Power's response to Attorney General's First Request, Item 1, KPCO_R_AG_1_1_Attachment2. Using the same weighted average cost of capital as that used in KPCO_R_AG_1_1_Attachment2, provide the annual revenue requirement effect for Kentucky Power in 2026 through 2028 associated with the non-ELG capital projects at Mitchell Plant that have previously been asymmetrically allocated between Kentucky Power and Wheeling Power. Include in the response the workpapers reflecting the calculation of those amounts in each year in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

RESPONSE

Please see KPCO_R_KPSC_PHDR_13_Attachment1 for the requested information.

Witness: Lerah M. Kahn

DATA REQUEST

KPSC PHDR_14	Refer to Kentucky Power's response to Staff's Fourth Request, Item 3, KPCO_R_KPSC_4_3_ConfidentialAttachment4. Provide an updated version of KPCO_R_KPSC_4_3_ConfidentialAttachment4 that reflects the removal of the 40 percent capacity factor limitation, including with respect to the "MWh of Generation."

RESPONSE

KPCO_R_KPSC_4_3_ConfidentialAttachment1 does remove the 40 percent capacity factor limitation. However, the CC GWh in row 36 on the "Input" tab was not appropriately updated to reflect this change from the "Plexos Output" tab. This only impacted the LCOE calculation within the file. Please see KPCO_R_KPSC_PHDR_14_ConfidentialAttachment1 for the updated file.

Witness: Alex E. Vaughan

KPCO_R_KPSC_PHDR_14_ConfidentialAttachment1 is redacted in its entirety.

Kentucky Power Company
KPSC Case No. 2025-00175
Commission Staff's Set of Post-Hearing Data Requests
Dated November 21, 2025

DATA REQUEST

KPSC PHDR_15 Provide the clearing price for the PJM Base Residual Auction in each year from 2020 to the most recent year available.

RESPONSE

Please see the table below for the PJM Base Residual Auction resource clearing price by delivery year from 2020 to present. This information is also publicly available at https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

Delivery Year	$/MW-day
2019/2020	$100.00
2020/2021	$76.53
2021/2022	$140.00
2022/2023	$50.00
2023/2024	$34.13
2024/2025	$28.92
2025/2026	$269.92
2026/2027	$329.17

Witness: Alex E. Vaughan

VERIFICATION

The undersigned, Lerah M. Kahn, being duly sworn, deposes and says she is the Regulatory Services Manager for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Lerah M. Kahn

Commonwealth of Kentucky)
) Case No. 2025-00175
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lerah M. Kahn, on December 4, 2025.

Marilyn Michelle Caldwell
Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Joshua D. Snodgrass, being duly sworn, deposes and says he is the Mitchell Plant Manager, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Signed by:
Joshua D. Snodgrass

Joshua D. Snodgrass

Commonwealth of Kentucky)
) Case No. 2025-00175
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Joshua D. Snodgrass, on 12/1/2025 | 2:13 PM EST.

Signed by:
Michelle Caldwell

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
COMMONWEALTH OF KENTUCKY
Commission #KYNP71841
My Commission Expires 5/5/2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Managing Director Regulated Pricing – Generation and Fuel Strategy for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

____
Alex E. Vaughan

_________________)
) Case No. 2025-00175
_________________)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on December 1, 2025.

____
Notary Public

My Commission Expires Does not expire

Notary ID Number ____________

NOTARIAL SEAL STATE OF OHIO
HAYDEN CAPACE
NOTARY PUBLIC - OHIO

VERIFICATION

The undersigned, Tanner S. Wolffram, being duly sworn, deposes and says he is the Director of Regulatory Services for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Tanner S. Wolffram

Commonwealth of Kentucky)
) Case No. 2025-00175
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tanner S. Wolffram, on December 4, 2025.

Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841